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PRACTICAL AND THEORETICAL FINANCIAL CONSIDERATIONS ON ELECTRICITY STORAGE TECHNOLOGY

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Abstract

This work project is intended to analyse the potential economic and financial impact of storage systems on all relevant agents in the electricity market. Regarding the practical dimension, a case study of the introduction of a PV system coupled with a storage unit on a service building of EDP Distribuição will be presented. Insights will be drawn regarding the current financial viability of this technology, technical constraints and the difficulties around determining an optimal algorithm which would govern the storage system's automatic charge and discharge process. On the theoretical dimension, through a hypothesising process and literature review, storage's impacts on grid management and price arbitrage are analysed. Finally, considerations are made on the expected shift in value between players, contingent on the ownership structure of the storage systems.

Keywords: Electrical Storage; Arbitrage; Ownership structure; Electricity markets

1. Context

1.1 EDP & EDP Distribuição

EDP – Energias de Portugal - is a vertically integrated utility corporation. EDP acts as the major electricity generator, distributor and retailer in Portugal and ranks as the third largest player in the Iberian Peninsula. As a relevant electricity operator in the global landscape, EDP is present in 14 different countries, from Portugal to the USA and China, and provides electricity and natural gas to more than 9.7m people, which correspond to 1.4 million customers. By December 2015, EDP had 24 gigawatts (GW) of installed capacity and its 2015 production amounted to 64TWh, 58% of which is renewable energy *(EDP, 2015)*.

EDP Distribuição (EDPD) is the subsidiary for the distribution of low, medium and high voltage electricity in Portugal. EDPD manages the grid under 278 low voltage concessions and a high/medium voltage concession during 35 years, renewed in 2009. Its responsibility is to ensure to customers the supply and quality of energy, grid management and commercialisation options. Additionally, the activity's remuneration is regulated by Entidade Reguladora dos Serviços Energéticos (ERSE), which, among other things, fixes retail prices. Moreover, EDPD plays a crucial role as the facilitator of the energy sector development, promoting initiatives such as electrical vehicles, smart grid implementation or matters such as the analysis conducted on this report – the study of storage and Photovoltaic coupled systems.

1.2 Industry and Regulatory Overview

The electricity sector has been under a severe transformation globally. Three large drivers of change are at play currently. Firstly, the growing environmental and CSR concerns set new challenges regarding ensuring sustainability. A new paradigm arose on the energy sector, based on high levels of investment in cleaner technology innovation, forced and incentivised by a large regulatory overhaul. A case in point is the European Energy Policy, which consists in the 2020 Energy Strategy, enforced through a European Union (EU) directive, aimed at reducing gas emissions by at least 20%. To do so, it mandates the increase of the EU's share of renewable energy to at least 20% of consumption, while achieving energy savings of 20% or more by 2020, relative to the baseline scenario *(Energy 2020 Directorate-Generale for Energy, 2010)*. Furthermore, all EU countries should achieve a target of 10% share of renewable energy in their transport sector. Recent reports have shown positive results and, in light of these results, at the end of 2015, the EU adopted additional goals for 2030 *(European Commission, 2015)* furthering the regulatory pressure. Players in the energy market seem to have followed suit as the overall share of renewable energy in the total energy production is expected to double until 2030 *(IRENA, 2015)*.

Secondly, energy commodity prices, such as crude oil, coal and natural gas, which are the largest inputs for electricity production, have experienced extreme historically high volatilities and considerable downwards price pressure *(Appendix 1.1)* over the past 4 years. This is partly due on the demand side by unstable macroeconomic conditions and deceleration of the largest importer economies. On the supply side, technological innovations such as hydraulic fracturing have allowed previously untapped pockets of natural gas and crude oil to be poured into the markets. To this one must add the direct military conflicts, or by proxy, which currently involve several oil producing countries. Given electricity's prices extremely high correlation with these inputs, any developments in the latter impact the former.

Thirdly, technological developments associated with the decrease in renewables' costs and improvement in performance have rebalanced the economic calculation in their favour. Some regions of Portugal had already achieved grid parity by 2015 (Deutsche Bank, 2015).

The combination of strong regulatory pressure, extreme volatility on traditional electricity inputs and technological improvements have incentivised utility companies such as EDP to diversify away from fossil energy and to pursue new opportunities within the renewable energy sector so as to adapt to this new paradigm.

1.3 EDPD's current situation

EDPD is currently facing two pressing issues of regulatory and economical nature:

1) In order to meet the European Directive to reduce CO_2 emissions and increase renewable energy production, EDPD aims to increase the efficiency of their service buildings.

2) EDPD has recognised the new trends on the electricity market, namely: technological developments on storage systems. It is keen about exploring two economic dimensions of storage systems. Firstly, it wants to explore whether storage deployed on a smaller scale can create value through cost savings by further replacing expensive grid electricity with cheaper PV generated energy. Storage could also allow for price arbitrage gains making use of the daily price spread, sourcing at off-peak prices and selling/consuming at peak prices. Secondly, it wants to understand the impact of massive storage adoption on improved grid management. This could be achieved through peak shaving, which consists in absorbing supply of energy in excess of demand, which occurs at peak production times, to be deployed at a later time. Supply peaks are heightened by intermittent power sources, whose surplus energy is normally wasted. Moreover, disposing of that energy might even carry a cost. Storage systems, by absorbing that surplus and later deploying it, allow for the smoothening of energy supply throughout the day.

1.4 The business challenge

EDPD's stated objectives for this business project were the following:

1. Creation of a conceptual business analysis of combined renewable energy production, self-consumption and energy storage in EDP Distribuição's buildings (based on multi scenario analysis),
2. Validation of the conceptual model's assumptions using real energy production values collected from the recently installed monitoring systems and using the variable energy price tariffs during a normal day.

3. Improve the business analysis model in order to incorporate the new technologies and establish recommendation to be followed;
4. Assess return on investment and energy efficiency benefits, both current and expected to allow for use in future projects.

2.1 EDP's Problem Statement

EDPD is looking to introduce a pilot project for a PV-coupled battery storage system in their service building in Évora, with the potential to leverage upon the new environmental and regulatory paradigm, as well as to get a better understanding of the technologies. Battery storage is a new evolving technology and can complement PV modules by better utilising renewable energy production. Particularly, the aim of the pilot program is threefold. Firstly, to improve service building's energy efficiency and thus allow for cost savings. Secondly, to improve its energy rating and thirdly to develop know-how about the emerging battery storage technology.

It should be noted that this problem has a particular dimension for EDPD because of its status as a distribution system operator (DSO). EDPD as a DSO injects PV generated energy into the grid without getting any compensation in return. It is therefore at a disadvantage versus private consumers which are compensated whenever they inject electricity onto the grid.

Analysis which addresses the broader challenge's goals and the project aims will be provided, followed by a recommendation to EDPD on whether it should develop the project, and, if so, on what scale. The recommendation will consider both a financial-viability aspect and also a broader non-financial perspective.

2.2 Methodology

The hypothesis which supports the BP's rational can be stated as follows:

"The use of a combination of photovoltaic technology and storage units, in this particular location, can simultaneously generate value for the company, measured by a positive

NPV, while improving its efficiency rating." To ascertain the validity of the hypothesis is then equivalent to deciding on whether the project should go ahead or not.

The main tool to test the financial viability of this project is the computation of a net present value (NPV). The NPV constitutes the output which informs the decision of whether to go ahead or not. It also identifies the relevant drivers of value creation or destruction that must be considered *(Fisher, 1907)*. The NPV was broken into three components:

1. Capex: PV and storage system
2. Operating Cash Flows: savings generated by producing/sourcing electricity at a lower cost through the project vis-à-vis the status quo (grid sourcing).
3. Cost of Capital: opportunity cost of the deployed capital according to the risk profile

The model is intended to be as dynamic as possible to allow for parameter change and therefore achieve: 1) Longer model lifespan; 2) Larger range of utilisation; 3) Ease of scenario testing. The objective is to make this model applicable to similar projects. Whenever possible, simplifying assumptions which do not materially alter the results, will be applied to make the model clearer and simpler.

The model's endogenous variables are PV Production Capacity in kW, a discrete variable, and Storage System Capacity in kWh, a continuous variable. However, fixed increments (5kWh) in storage capacity will be considered to align with the current available offer of batteries. The model reflects an actual electric system and as such must reflect all relevant technical constraints. The latter include maximum storage capacity, energy transmission rate (power) and grid balance, i.e., Load (energy consumption) must be equal to energy supply.

All the relevant inputs required to compute the model were provided by EDPD and will be critically assessed. To do so, market research data from several independent sources was collected and compared to EDPD's provided data.

Given the uncertain nature of these inputs, sensitivity analysis will be conducted to assess the impact of estimation error on the project's conclusions.

For simplicity purposes, the model is split into two stages which correspond to two different algorithms. Stage I model is a simplified approach to the problem, including less variables and only considering one business case - peak shaving, i.e., the mitigation of the strong variability of solar energy production during the day. Regarding the approach to stage I modelling, firstly, the analysis revolves around determining what variables are relevant to operationalise the model. Secondly, a conceptual model is created to test compliance with technical constraints. Finally, the conceptual model is built on a software package. The lessons learned from Stage I are then to be used to build a more sophisticated Stage II model. The Stage II model is expected to have three add-ons: 1) a stochastic forecast of the PV production and Load in order to make the battery storage system more realistic; 2) the introduction of price arbitrage as a second business case, i.e., pro-actively exploring the electricity price differentials throughout the day; 3) a more efficient battery discharge mechanism.

For the analysis of both stages of the model, the underlying electrical system can be simplified into the following four components (note: all technical non-actionable components, e.g. inverters, will be ignored): 1) PV production unit, which has a lifetime of 20 years; 2) Electrical consumption unit; 3) Storage Unit - Battery, which has a lifetime of ten years; 4) External provider of electricity - grid. Therefore, the model runs over 20 years with a battery storage capacity for the first ten years.

PV production, battery stored production and grid electricity are available for consumption. In order to avoid shortages, the sum of PV production, battery and grid electricity sourcing must be equal to consumption (Load). If PV production is in excess of Load and there is no storage capacity left in the battery, the excess will be forwarded to the grid at no compensation (price = 0). An auxiliary visual representation can be found in *Appendix 2.2.A* (stage I) and *2.2.B* (stage II)

2.3.1 Stage I model

On Stage I, there is only one flow of energy to the storage unit: the surplus of PV over Load. The aim of the developed model is to maximise the NPV of the project, subject to meeting all relevant technical restrictions. As stated above, the NPV will be a positive function of the Operating Cash Flow (OCF) – savings; and a negative function of Capex and Cost of Capital. Cost of Capital is exogenous and determined by EDPD (see limitations). OCF and Capex can be assessed with respect to two actionable variables: 1) Storage Capacity in Watts Hour (Wh); 2) PV Production Capacity in Watts Nominal (Wn). The maximisation process of the NPV will thus revolve around these 2 endogenous variables. For a detailed explanation, visual representation of the algorithm powering the mode, exhaustive listing of all variables and price tariffs see *appendix 2.3.1.A-D.*

2.3.2 Conclusions

Firstly, the analysis determined Storage Units to be non-financially viable. The result of the optimisation process determined zero storage as optimal. That means that the enabled usage of surplus from PV in excess of Load, which would otherwise go to waste, was not enough to cover the costs of setting up the system. It should be noted, however, that a positive NPV (although below optimum) can be attained resorting to storage. That means that, although the highest PV is found when using zero storage, it is possible to obtain a positive, lower value NPV while using storage *(see appendix 2.3.2.A-B)*

Regarding the second point, the optimum PV Capacity was determined to be 15 kWn. It presented the largest optimised NPV of all four PV scenarios with zero storage capacity. It can be further concluded that the Load for the consumption unit in Évora is small enough so that no larger PV capacity is required. For the 15kWn, the optimum PV system, virtually no PV production in excess of surplus takes place, again reinforcing the lack of an economic case for storage (*see appendix 2.3.2.C).*

Thirdly, the results of the analysis recommend the development of a zero storage 15 kWn PV system as of today. Its NPV was estimated at 6,141€ for the Évora consumption unit. The project is expected to yield a 10.71% IRR on the 30,000€ PV system investment cost.

Regarding the largest value drivers, the top three variables ordered by importance were identified as being: PV Capex costs, WACC and Peak electricity prices. These exhibited large multipliers, i.e., the ratio[1] of percentage of variance of input over percentage of change in NPV. Those multiples are asymmetrical, so a positive variation of x% does not generate the same magnitude of impact on the dependent variable as a –x% variation. Upside multiples for the three variables under the zero storage 15kWn ranged from 4.89x to 1.08x. Downside multiples ranged from -4.89x to -1.08x. It was also concluded that larger PV Systems exhibit higher leverage (considering Capex as a lump sum fixed cost), making their respective NPV much more sensitive to changes in variable items (variable costs and revenues). Finally, WACC was found out to have a non-linear relationship with NPV with lower downside than upside. PV cost per kW and Peak Electricity Prices were found to be linear. For further detail on sensitivity analysis, breakeven prices and seasonality *see appendix 2.3.2.D-G*

[1] $Multiplier = \frac{\Delta\,\%\,Variation\ in\ NPV}{\Delta\,\%\,Variation\ in\ input\ variable}$

2.3.3 Implications for stage II

There are two main takeaways that help design Stage II. Firstly, the storage technology is non-viable as of yet because of its high capex compared to its enabled savings. As such it is paramount that the model of charge/discharge be refined to make the most use of the storage system. Secondly, given that NPV is extremely sensitive to shocks in several input variables it is prudent to introduce a stochastic dimension to replicate similar shocks. That stochastic dimension is also necessary to reflect real life PV production and load prediction limitations.

2.4 Stage II model

The main difference versus Stage I is that now the battery can be charged by another source in addition to PV: the grid. As such there are now two flows to battery: 1) PV to Battery; 2) Grid to Battery *(Appendix 2.2.B)*.

The stage II model can be seen as an extension of the stage I model, and therefore a large portion of it is the same. The exact same three checks: balance check, capacity check and power check are executed to determine whether PV produced energy in excess of Load can be stored in the battery. All the relevant variables are exactly those previously listed. All flows between PV to Battery and PV to consumption unit follow exactly the same logical and technical restrictions. The innovation comes in relationship to the battery. As under stage II, the battery is allowed to tap the grid to source energy, a new model, which determines the logic behind the charging and discharging of the battery, was required. For a detailed explanation of the model, stochastic process and a visual representation see *Appendix 2.4.A-E*

2.4.1 Results

Similarly to stage I, the NPVs of the four PV scenarios exhibited monotonous and non-linear decrease in value as storage capacity increased. However, the losses in NPV are now lower than in stage I. For these levels of storage capacity, the NPV varies less than proportionally to the increase in capacity *(Appendix 2.4.1.A-B)*. The storage systems considered separately from the PV are non-financially viable i.e., the cost savings allowed by the storage system do not cover its Capex.

The higher the PV production capacity for a given load, the lower the loss supported in absolute terms when moving from 0 storage to 5kWh worth of storage. This is because higher capacity PV systems can utilise a 5 kWh storage to a fuller potential than lower PV systems.

Levelised Cost of Energy (LCOE) consists of calculating the cost of electricity per kWh generated, per technology, adjusted by the time value of money *(see appendix 2.4.1.C-G)*. This method's results are aligned with the NPV ones. The LCOE of a 5kWh storage system combined with a 15kWn PV system is 0,56 €/kWh which is 3.67x the LCOE of grid electricity (0,153 €/kWh), proving buying electricity from the grid is superior to using a storage system. However, a 15kWn PV system alone with an LCOE of 0,142 €/kWn is 7,6% cheaper than the grid LCOE.

The required NPV breakeven prices per €/kWh of storage capacity are lowest, the higher the PV system capacity and the higher the storage capacity. Breakeven prices range between [320€/kWh; 1.669€/kWh]. Starting from the baseline assumption of 1200€/kWh and assuming industry's forecasted 10% decrease a year continues would lead to storage costs around 700€/kWh in 5 years. That would make the 10 kWh system financially viable with all PV systems bar the 25 kWn and the 15 kWh system viable for the 15 kWn and 17 kWn PV systems *(Appendix 2.4.1.H)*.

Regarding payback periods, at the current storage assumption of 1,200€/kWh, it ranges between [7.8; 10.8] years.[2] Storage Capex is a small fraction of total Capex expenditures, ranging from [10.7%; 37.5%]. As such, even with decreases in price of around 50% in five

[2] does not consider the time value of money

years to 600 €/kWh, that would generate reductions in the payback period between [5.4%;18.8%] for a new payback range between [7.4; 8.8] years *(Appendix 2.4.1.I-J)*.

2.4.2 Conclusions

Firstly, the PV system coupled with the storage system was determined to be financially viable, but suboptimal. For all tested battery systems, the LCOE, i.e., the cost per kWh of energy produced, adjusted by the time value of money, was higher than grid electricity prices. Therefore, given the current cost of battery systems, it is more financially profitable to opt for PV systems alone.

Secondly, for any given PV system and respective storage system, stage II provides better results than stage I. This is attributable to a refined process of charging and discharging, which both limits energy wastage and ensures energy deployment at higher prices, maximising the value of energy. The 15 kWn PV was able to improve its result for a 5 kWh battery by 2.37x and the 25 kWn was able to cut its loss by approximately 13%.

Thirdly, NPV is, as in Stage I, maximised through the usage of a 15 kWn PV system. This holds true both for PV systems with zero storage and for any level of storage capacity. As in Stage I, the NPV of a 15 kWn PV system with zero storage was computed as 6,141€, providing a 10.29% IRR on a 30,000€ investment on the PV System.

Furthermore, the largest value drivers were calculated for PV systems combined with a 5 kWh storage system. Ordered by the magnitude of their impact on NPV, they are: PV System Capex, peak electricity prices and WACC. For 10% shocks in these variables, the NPV of the 15kWn PV coupled with 5kWh storage displayed increases[3] between [1.28x; 0.7x] and decreases between [-1.28x;-0.7x].

[3] These increases are measured as $\frac{\Delta NPV}{NPV_0}$

Lastly, the introduction of a storage system increases leverage on the NPV. This means NPV becomes more sensitive to changes in its inputs. Therefore, additional care must be taken with accompanying their evolution over time. Compared to model I, the necessary breakeven storage system costs are now higher, therefore making an installation of a storage system viable at an earlier time. Storage systems' Capex, although expected to decrease significantly in the near future, constitutes a small fraction of total Capex. For small Load/PV profiles such as the Évora service building, where small capacities are optimal, a 50% reduction in storage Capex would only lead to an 8,3% total Capex reduction.

2.4.3 Sensitivity analysis

In what regards the storage system's Capex, there is a linear inverse relationship between its value and NPV. For the 15 kWn system with a 5 kWh storage, an increase/decrease in storage Capex of 50% is expected to decrease/increase NPV by 128%, twice as much the change to NPV caused by a 25% change in Capex (64%). Moreover, the 50% drop in prices is expected to occur between 5-6 years under current rates. For the 25 kWn, the same 50% increase/decrease in storage Capex is expected to decrease/increase NPV by 64%, twice the impact caused by the 25% change. Its linear relationship with NPV reduces its impact when compared to non-linear variables. When storage Capex is simultaneously shocked alongside the storage capacity, the impact of storage increases. Coupling the 50% increase/decrease in storage Capex with a 50% increase/decrease in storage capacity leads to a total variation of 4.2x NPV for the 15 kWn PV, and a total variation of 2.1x for the 25 kWn. *(Appendix 2.4.3.A-B)*

In what concerns the PV system Capex, an increase/decrease of 10% for the 15 kWn is expected to correspond to a decrease/increase of the NPV by 128%. The same 10% increase/decrease would decrease/increase the 25 kWn's NPV by 110%. Looking at absolute variation of NPV, it can be seen that the 25 kWn NPV's variation is 1.67x higher than the 15 kWn one. Despite the high multipliers, given the historic trend of price decreases for PV modules, it seems unlikely that NPV losses would materialise.

Analysing changes in peak electricity prices under a 5 kWh storage scenario leads to the following results:1) In what concerns the 15 kWn, an increase/decrease of 10%, is expected to impact the NPV with an increase/decrease of 70%; 2) The 25 kWn appears to exhibit less leverage. For the same 10% increase/decrease in electricity peak prices, the NPV is expected to increase/decrease by 42%. However, when looking at absolute values, the variation in NPV for the 25 kWn is actually 1.18x that of the 15 kWn, illustrating higher leverage. Comparing the absolute variations of a 5 kWh storage's NPV versus a zero storage situation, the NPV became more leveraged with the introduction of a storage system – 1.21x more sensitive to price changes for 25 kWn and 1.24x more sensitive for the 15 kWn. With the prospect of further future liberalisation of the distribution market, this is an important area to keep track of.

2.5 Recommendations to EDPD

EDP is advised to implement a 15kWn PV system coupled with a 5kWh storage system on its Évora service building as a pilot project. The reasons for this can be split by financial and non-financial nature for both variables: PV and storage system's capacity.

Regarding the financial criteria of NPV maximisation, the optimal solution reached is a 15 kWn capacity PV system with no storage, leading to an NPV of 6,141€ over the 20-year time horizon. The proposed solution in this recommendation would yield a 2345€ (62% below optimum) and an IRR of 8,9% on an investment of 36.000€.

Looking at the PV capacity, its computed optimum of 15kWn results from the consideration of adequacy of electricity production by PV with Évora's service building requirements. The analysis suggests Évora's might be too small to justify PVs of capacity superior to 15kWn as increasing its capacity has the effect of diminishing NPV. Even when considering larger PV's capacity increased utilisation of a given storage system, it was found that the incremental savings from stored energy did not cover the incremental capex.

Looking at storage capacity, given the current state of the technology, the financial optimum would be to skip its introduction entirely. However, at an incremental loss of -3796€ vs the optimum, it is a perfectly absorbable non-material loss. Should other considerations, which will be elaborated on, be considered, the case for installing storage now would be made clear despite the negative NPV.

Non-financial considerations can be split into 3 dimensions. Firstly, EDPD has taken on a commitment to improve its energetic efficiency. Introducing storage which can minimise grid reliance, which has a less green energy mix (non-renewables >50%), fits this goal. Secondly, interacting with this new technology from the onset can allow for: 1) know-how to be created internally, which can later allow for lower cost, customised deployment and even commercialisation of this technology; 2) pre-emption of entrants with business models substitute to that of EDP's. Finally, fostering the technological development of this technology might be in the in best interest of EDP as a grid manager. With mass adoption, idle batteries could absorb spikes in electrical production and, similarly, full batteries could fulfil peaks in demand, which would otherwise rely on expensive or pollutant generation solutions. By smoothing electricity demand and supply (peak shaving), storage would reduce grid management costs. All these arguments are further strengthened by the trend in storage cost reduction which may lead to viable small systems in as little as 5 years' time, which suggests high adoption potential.

Finally, during the project's lifetime, it is critical for EDPD to pay special attention to the price developments of the PV system, electricity prices (regulated) and storage capex. Changes in the latter may justify a change in storage capacity at the time of replacement of the first unit after 10 years. At which point the replacement storage system is fully expected to be financially viable.

2.6 Limitations and concerns

The model developed has a few known shortcomings. Firstly, the battery's degradation is not modelled throughout its ten years' lifetime. Instead, it is expected to work at its full potential until it completely breaks down. In a more sophisticated model, the battery would experience a somewhat linear degradation over the years. However, the rate of degradation is uncertain as the technology is still under a development phase. Secondly, the model does not perfectly appropriate savings opportunities. It either discharges the battery on peak periods, therefore missing on the also profitable "cheia" periods, or it discharges the battery in "cheia" and peak periods, requiring higher charging from the grid during the night. Carrying that full storage can sometimes cause zero marginal cost PV production in excess of Load to be thrown out from lack of storage space, inducing a loss. Logically, this problem could be solved through a conditional maximisation process. However, it is too technically complex to be executed. Thirdly, PV production forecasts should be based on a weather forecast model in order to better predict the optimal solution for the storage battery.

Secondly, the model is based on assumptions regarding critical inputs. Because it is impossible to dispel these concerns, a sensitivity analysis was conducted whose findings did not alter the recommendation. Additionally, careful research was conducted so as to provide a reality check:

- PV: Market research suggested an average price of around €2,000/kW and therefore is in line with the incorporated price assumption of €2,000/kW. The use of a PV degradation rate of 0.7% is justified when compared to contemporary PV modules *(Appendix 2.6.A-B)*.

- **Battery system**: The price of 1,200 €/kWh as well as the life expectancy of 10 years, approximately 3,600 cycles, are rather conservative assumptions but as the technology is still new, it seems reasonable *(Appendix 2.6.C-E)*.

- **Discount rate:** EDPD proposed a discount rate of 8% for this project. Based on research about discount rates of the industry, this rate falls within the range for vertically integrated utility companies of 7.7-9.5%. (CMA, 2015). Furthermore, using the CAPM, a similar WACC can be found *(Appendix 2.6.F)*.

2.7 Individual contribution

My individual contribution to the business project can be split into process and output contributions. A relevant piece of context is that I was the technical expert of this project who developed the algorithms/models.

Regarding process contributions, I would start by highlighting that I developed the methodology which was used to tackle the problem. Before even conceptualising the technical model, I reflected on how to address the problem and wrote a draft of what would become methodology. I established that the way to more accurately assess financial viability would be to compute all the energy that the several PV and battery systems would generate. Crossing that hourly energy volume with the hourly grid prices told me exactly how much value I was creating by avoiding sourcing energy from the grid. This value would then have to be deducted by the hourly operating costs, capex, and adjusted for the time value of money. This was an improvement to the lump sum comparison of total cost of energy with the project and without the project that EDPD initially suggested. My method of breaking the flows down allowed for more refined analysis, study of the different value drivers and conduction of sensitivity analysis. I was also responsible for structuring the technical aspect of the model as was hinted above. After initiating the model conceptualisation, I quickly realised that due to its complexity it would not be feasible to implement all of EDPD's requirements into a single model on a short period of time. As such, I proposed the breakdown into two stages, so as to have a proof of concept early on. That would allow the appreciation of its limitations and to receive feedback which could be later incorporated.

Still on process contribution, I would also highlight my early engagement and consistent work throughout the semester. The day after getting the data, I had already compiled and emailed a significant number of clarification questions back to EDPD. I believe that this simultaneously signalled to EDPD that we were serious about the project, while it also set a high pace for the group (which I find to be motivating). From the first week onwards, I put in hours consistently which materialised into: 1) an improved model; 2) additional questions to be solved; 3) a log of work done and to be done. As such I was able to present significantly new material at every weekly presentation with EDPD. All EDPD feedback was incorporated between meetings and new content was developed. Because of the project's technical nature and given my specialisation in the technical aspects, I became the bridge between EDPD and the group. This materialised on the following: firstly, I usually took the lead in meetings (because I had the most to say); secondly, most communication between the group and EDPD flowed through me (requests, clarifications); thirdly, despite being working part time, and therefore having no opportunity to meet our business advisor, I provided debriefs of the most relevant meetings with EDPD. Finally, my last contribution on process was to provide an explanation of every technical topic to my group. I also made all of my auxiliary documents with annotations available online, so that everyone could keep up with the technical part of the project.

Regarding my output contributions, I believe them to be quite significant for the overall deliverable. Firstly, I developed the conceptual model for both stages, which is exemplified in the algorithms explanation and visual representation. Secondly, I implemented the conceptual model onto excel. Throughout the semester, the model went through significant changes, as either inputs from EDPD were implemented, or previous ideas were found not to be technically feasible. That activity took me the most hours of work. Thirdly, having created and implemented the model, it followed that its explanation for both stages would fall upon me. Fourthly, having written the model, I interpreted its output and wrote the results segment. Fifthly, I interpreted these results and, based on those findings, I wrote the preliminary conclusions per stage. Sixthly, I developed an alternative analysis based on a paper that was brought to my attention by a group member, the Levelised Cost of Energy (LCOE) analysis. This alternative analysis was relevant in corroborating the results of the model. Additionally, it provided a sense of the order of magnitude which separates value created by storage versus grid sourcing or PV production alone. Finally, I built the sensitivity analysis on to the model and wrote its findings. Because all of this information was quite dense and number rich, I provided an appendix as complete as possible, with tables and graphs to allow for an easier read.

Regarding joint output contributions, I collaborated on writing the general conclusions of the business, which can be seen as the recommendation, and on the limitations of the model. I focused on the technological implications for EDP as a grid manager. Taking a macro perspective allows the company to weigh in other non-measurable value which would otherwise go unconsidered. On the limitations, I provided an account of model deficiencies, and the reasons for them to have gone on uncorrected.

3. Academic Discussion

The consideration of the adoption of energy production and storage systems has pervasive connections with several branches of theoretical finance. Here, a brief literature review will be conducted and some considerations will be made regarding the impact of storage systems. The scope of the impact analysis will be limited to impact in distributed generating technologies through synergies, arbitrage gains in electricity exchange and retail based markets and on the consequences of different ownership models. Additionally, the contrarian view to the technology will be briefly presented and its merits considered. Finally, future venues for research will be proposed.

The case for storage adoption can be made from two distinct perspectives. The first perspective pertains to grid management. Several authors recognise that sufficiently large capacities of storage system put in place are one of the most effective ways of dealing with renewable energies' intermittent power flows (Reihani, Sepasi, Roose, & Matsuura, 2016). Indeed, storage acts through the supply side, creating flexibility and complementing on improvements to demand management and energy allocation through smart grids (Crespo et al., 2016), therefore minimising grid operation costs. The second perspective pertains to the possible cost savings or financial gains that can be made through the exploration of the energy price spread throughout the day, which again has been vastly explored in the subject's literature (Graves et al.,1999), (Figueiredo et al., 2006) and (Walawalkar et al., 2007).

The following analysis pertains to the latter perspective. As has been explained, storage allows for arbitrage gains through the charging at off-peak prices and discharging, be it through sale or consumption, at peak price periods. Generally, storage is assumed to be deployed by the consumers seeking a smoothing of their Load procurement, so as to minimise their charges (for a set volume of Load). It becomes then interesting to extend on this topic in two particular areas. The first is to move from an individual perspective into an aggregate one and to assess its impact to the overall electricity market and aggregate welfare. (Sioshansi, Denholm, Jenkin, & Weiss, 2009) conducted this analysis on the electrical market of the District of Columbia, US. Their findings were quite significant. Firstly, the massive adoption of storage, through its facilitation of phased Load procurement, is expected to alter peak and off peak price profiles. Peak prices are expected to go down and off peak prices to up as the demanded quantities from grid move downwards and upwards respectively. Secondly, the higher the adoption rate, the lower the arbitrage opportunities are available to explore as the spread shortens. It then follows that storage system adoption eliminates arbitrage opportunities within the electricity market. Their quantification attempt suggests that each GW of storage can result in “annual consumer surplus gains on the order of $16-35 million and producer surplus losses in the range of $14-31 million”. Extrapolating to the Portuguese market, one would find that, per storage system of 5kWh, EDP would be poised to support an annual surplus loss between 70 and 155$. However, the following caveats apply: 1) the price spread is distinct; 2) EDP still largely commands monopoly power; 3) regulation considerations may prove relevant.

The second area, which is of interest to explore, is on how financial ownership of these storage systems can determine its impact on the electricity market through differing incentives. An exceptional contribute to this area of study is provided by (Sioshansi, 2010). Three models of storage ownership are considered: consumer ownership, energy generators ownership and independent storage operators' ownership. In order to assess the implications of ownership, the author developed an intuitive model. The following assumptions must hold: 1) Load demand is assumed to be price-inelastic; 2) Prices are a linear function of Load $(l) = C_0 + C_1 * l$; 3) The electricity market operates on a simplified two period tariff – peak and off-peak, respectively period 1 and 2. Two relevant variables are storage efficiency as measured by the % of charged energy energy available for discharge after transmission losses - η and discharged energy - δ. Using this simple terminology and assumptions one can model the impact of an introduction of storage on the welfare of each of three agent categories *(visual representation on appendix 3.A).*

$$\Delta Consumer\ surplus = \ l_1 \left[p(l_1) - p(l_1 + \frac{\delta}{\eta})\right] + l_2[p(l_2) - p(l_2 - \delta)]$$

$$\Delta Generator\ surplus = \ C_1 . l_1 \left[\frac{l_1}{\eta} - l_2 + \frac{1}{2}\delta + \frac{1}{2} . \frac{\delta}{\eta}\right]$$

$$Arbitrage\ Value = \ \delta[p(l_2 - \delta)] - \frac{\delta}{\eta}\left[p(l_1 + \frac{\delta}{\eta}\right]$$

In these simple equations, it can already be seen the mechanism through which surplus is rebalanced. Consumers will source an additional $\frac{\delta}{\eta}$ at off-peak prices (period 1), elevating the cost of previously purchased quantity l_1 by $p(\frac{\delta}{\eta})$, incurring in a loss of surplus. However, because consumers have charged their battery in period 1, in period 2 (peak prices) they will need δ less energy from the grid. In doing so, l_2 will be partially sourced at $p(l_2 - \delta) < p(l_2)$, with the remainder load sourced (stored) at $p(l_1 + \delta)$. The generators will experience the same flows but with an inverse sign. It is possible to extrapolate what will be net impact in surplus reallocation between consumers and generators. By definition, l_2 which corresponds to peak demand, exceeds l_1 which corresponds to off-peak demand. As such, it is possible to infer that the peak-price decrease in the larger Load l_2 will outweigh the increase in off-peak price for the small l_1 Load. This is contingent on two factors: 1) the price spread being wide enough so that $p(l_1 + \delta) < p(l_2)$; 2) the battery's recuperation rate being sufficiently high so that the additional % of energy sourced to compensate transmission losses is smaller than the price savings ratio $\left(\frac{1}{\eta}\right) < \frac{p(l_2)}{p(l_1)}$. That being the case, the introduction of storage would constitute a net gain for consumers and a welfare loss for electricity generators.

(Sioshansi, 2010) demonstrates that the unconstrained storage optimum which maximises aggregate value is given by the following equation: $AV(\delta) = \frac{C_0\left(1-\frac{1}{\eta}\right)+C_1(l_2-l_1*\frac{1}{\eta})}{C_1*(1+\frac{1}{\eta}^2)}$. It follows that the higher the price differential between peak and spot prices $C_1(l_2 - l_1)$, the larger aggregate benefit of larger storage capacities and hence the benefit of introducing storage technology. It also follows that the higher the battery's energy recuperation rate η, the higher the storage capacity which maximises aggregate value.

Attention is now directed towards the financial impact of different ownership of the storage units. Like (Sioshansi, 2010) suggests, a careful study of the incentives of each agent provides a solid starting point. In case consumers hold ownership of the storage systems, they will try to simultaneously maximise arbitrage gains and consumer surplus. The author suggests, that out of the non-consideration of the generators surplus, overuse of storage will take place. Inversely, generators will try to maximise arbitrage gains while maximising their generator surplus. Unless arbitrage gains are quite significant compared to the value of Load demanded at peak periods, little to no storage will be utilised (underuse). Finally, independent storage operators are different in that they would only be concerned with maximising arbitrage gains and therefore deserve further analysis. Determining whether operators would approximate the aggregate optimum or not is a function of the market structure. This can be seen as an oligopoly market where the decision variable are quantities (storage capacity). In case storage symmetric operators can also service Load demand, a simultaneous cournot game with N>=1 finite players is assumed. The price of deployed energy, at time 2 (peak prices), is a negative function of l_2 load supply $P_2(ls_2) = a - b.ls_2$. Load supply can also be seen as a function of storage capacity $ls_2 = f(\delta)$. In which case the equilibrium arrived at would be such that $ls = N * \frac{a-mgcost}{b(1+N)}$, where marginal cost is composed of sourcing costs and operating costs, therefore $ls = N * \frac{a-\left[p(l_1+\frac{\delta}{\eta})+ mg\ op.cost\right]}{b(1+N)}$. Therefore, δ - storage ($ls = f(\delta)$) would be lower than perfect competition but higher than monopoly equilibrium. It appears that independent operators would underuse the storage system. The higher the storage usage, the lower the arbitrage opportunities to be explored and the lower the supra normal profit per storage operator.

On a concluding note, whatever the type of agent with ownership of the batteries, the higher its number of members and the closer the system will come to an aggregate optimum. That is because the larger the number of players, the more the system will converge to a point in which all agents are price takers, and whose decision cannot materially impact their and the other group's surplus and the arbitrage opportunities. However, through its numerical example

(Sioshansi, 2010) suggests that for finite players per type of agent, the model of ownership which comes closer to that an aggregate optimum is that of independent operators.

While some literature exists that suggests that storage solutions should be cast aside in preference of other solutions (Connolly, Lund, Mathiesen, Pican, & Leahy, 2012), the most common criticism is that alternative technologies are more economically viable in the present day. As such, much of the criticism would be mute should the technology improve enough to deliver superior value creation.

Finally, I can see four paths for improvement and future research. Firstly, the currently available theoretical models fail to account for the additional value created (synergies) by allowing intermittently produced energy, which would otherwise be wasted to be put to use. Secondly, it would be interesting to study whether integrated utility companies, which simultaneously manage the grid and produce energy, may actually find storage financially interesting. This could occur, in case they would be allowed to discontinue high fixed cost peak serving plants, and in case grid management costs would go down as the price spread and volatility diminishes. Thirdly, it would be interesting to introduce a more realistic non-linear price model to the previously mentioned models to determine whether the conclusions would still hold. Finally, adapting the model to a particular country's regulatory and market reality and to feed it with the relevant inputs would allow for a consideration of the order of magnitude of value created. This could be used to assess whether the value created compensates the investment cost and by whom and how such a project can be funded.

4. Personal Reflection

This project was an important learning opportunity and as such it is important to highlight both what went well and what were my shortcomings. I believe there were 4 main strengths at play and 3 weaknesses. Firstly, I exhibited a high engagement throughout the project. Not only did I start working the very same day we were provided the materials, but also tirelessly strived to improve the model, oftentimes going above expectations. Additionally, the area was new and interesting to me, so it kept me motivated throughout the semester and in good spirits. An example of this engagement was my effort to learn further visual basic code so as to overcome excel's limitations and build a more complex model. Secondly, I planned every step of the way and systematically checked the project's progress against my plan, and adapted either the plan or my posture accordingly. Thirdly, I believe I communicated with EDPD in an effective way. I explained the model's progress thoroughly on a weekly basis, conveyed and received feedback and discussed in abstract different alternatives going forward. Regarding the group, I communicated clearly the progress of the model, oftentimes briefing them for 1-2h before the meeting with EDP. Finally, I was rigorous during the execution process, auditing the model and going over the results critically several times, performing reality checks.

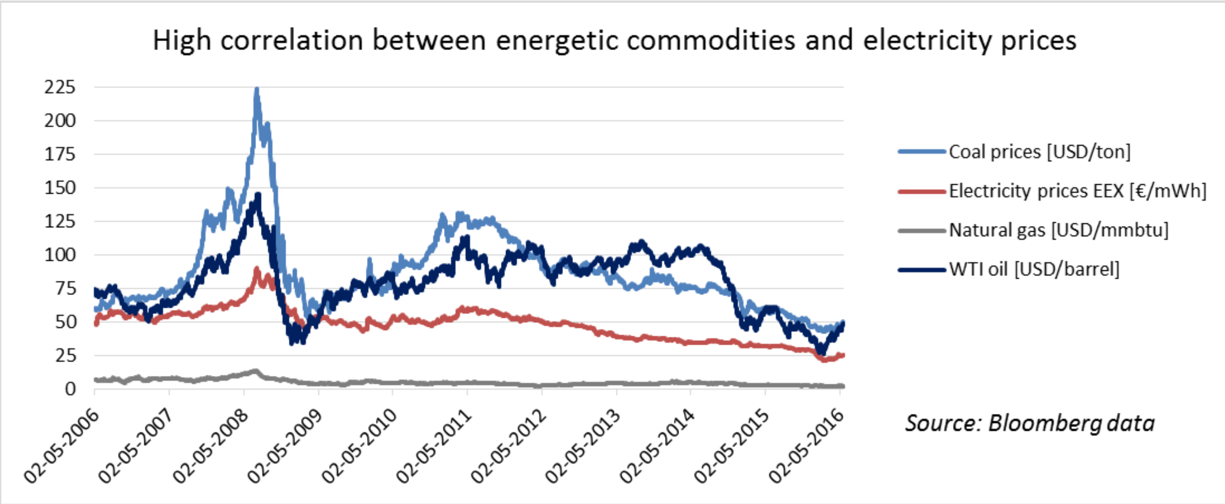
Looking at my shortcomings I would start by highlighting the unbalanced work split that led me to shoulder a large portion of it. While it was partially determined by work indivisibilities, it also had to do with my will for the model to reflect my ideas. Moreover, as the work progressed and I had more emotional investment in the ideas implemented, the less likely it became for me to delegate its continuation. By then, the model was complex and I had a comparative advantage, so the remaining group members never suggested or asked to participate in its construction. Another relevant self-criticism is that, due to my emotional investment in the model, I found myself improving details which were extremely time consuming but which provided little to no added value. That most certainly does not abide by management's maxim of 80/20, and that work could most certainly have been dedicated to more value creating activities. For example, I would have spent more time revising the text and improving its clarity. Finally, I found myself having a hard time cutting on good ideas which had been implemented and which were correct, but just not relevant. By this I mean that, occasionally, instead of taking a client (business advisor) centric approach, I was more concerned in developing an intellectually stimulating optimum model. And as I learned throughout the master's program, rarely is the technical optimum the adopted solution.

What created the most value was most definitely the planning, having weekly meetings with our business advisor and structure sessions with our academic advisor. Planning allowed for the work to be distributed fairly homogenously throughout the semester and, therefore, there were never stressful situations. It also allowed certain ideas to be ruled out before time being lost in their implementation. Secondly, once we started meeting regularly with EDPD, progress accelerated tremendously for two reasons. We got regular experienced feedback which we could incorporate, and it created some pressure for new work to be presented every week to EDPD. Finally, discussing the structure with our business advisor made us more aware of its importance and allowed us to improve it throughout the semester by incorporating feedback.

Taking all this into consideration, I must work on three distinct lacking areas. Firstly, I must learn how to better split the workload and leverage on every group member's skills. This can be done by becoming conscious of when I concentrate excessive work on me and to stop myself immediately and reflect on whether that makes sense. Secondly, I must force myself to take a macro perspective and reflect at every stage if the work being done compensates the effort put in (80/20 rule). Thirdly, I must listen more attentively to whomever the work is delivered to and tailor it exactly, so it matches their preferences, not mine. Finally, I would reinforce my planning practices and increase interaction with clients, group members and advisors, seeing as that contributed so much to an improved output. Progress on implementing these solutions can be tracked by keeping a log of every meaningful task and group interaction, and adapting my actions accordingly.

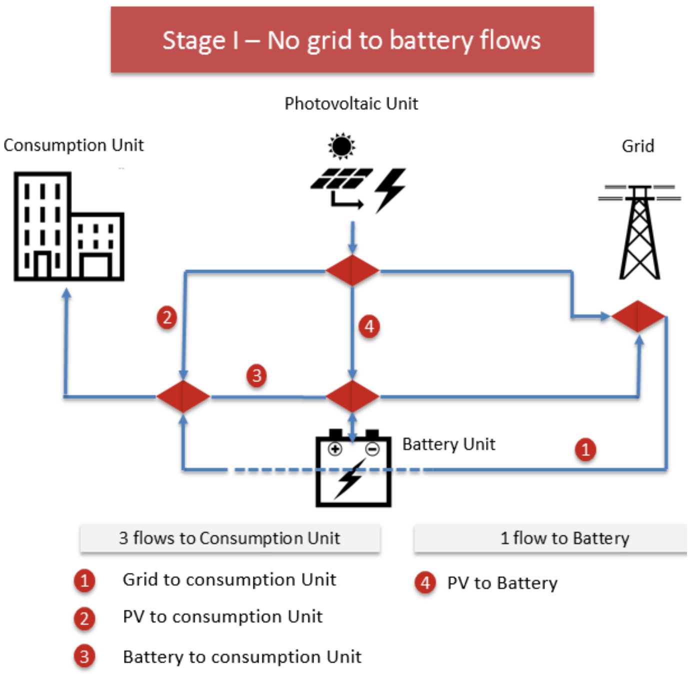
Appendix for context

Appendix 1.1 – Correlation between fossil energy sources and electricity prices

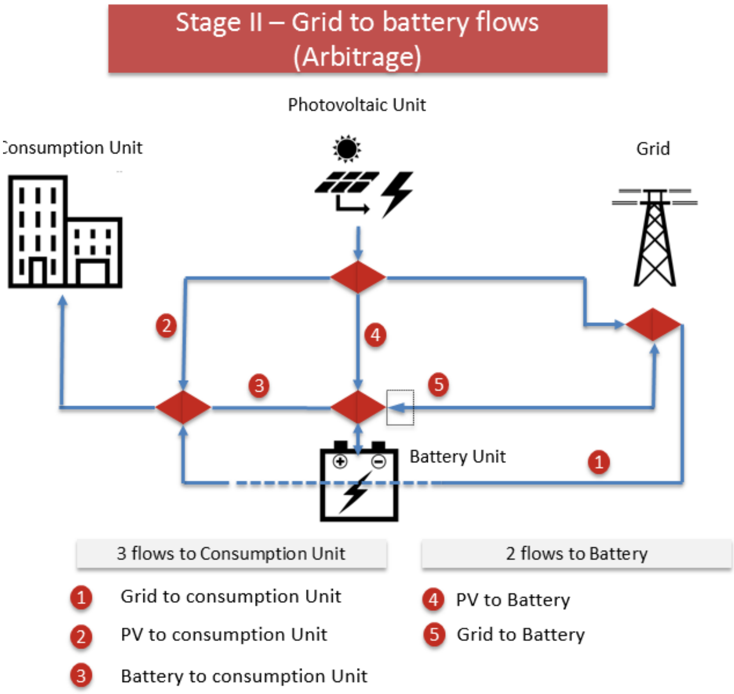


Appendix for Model

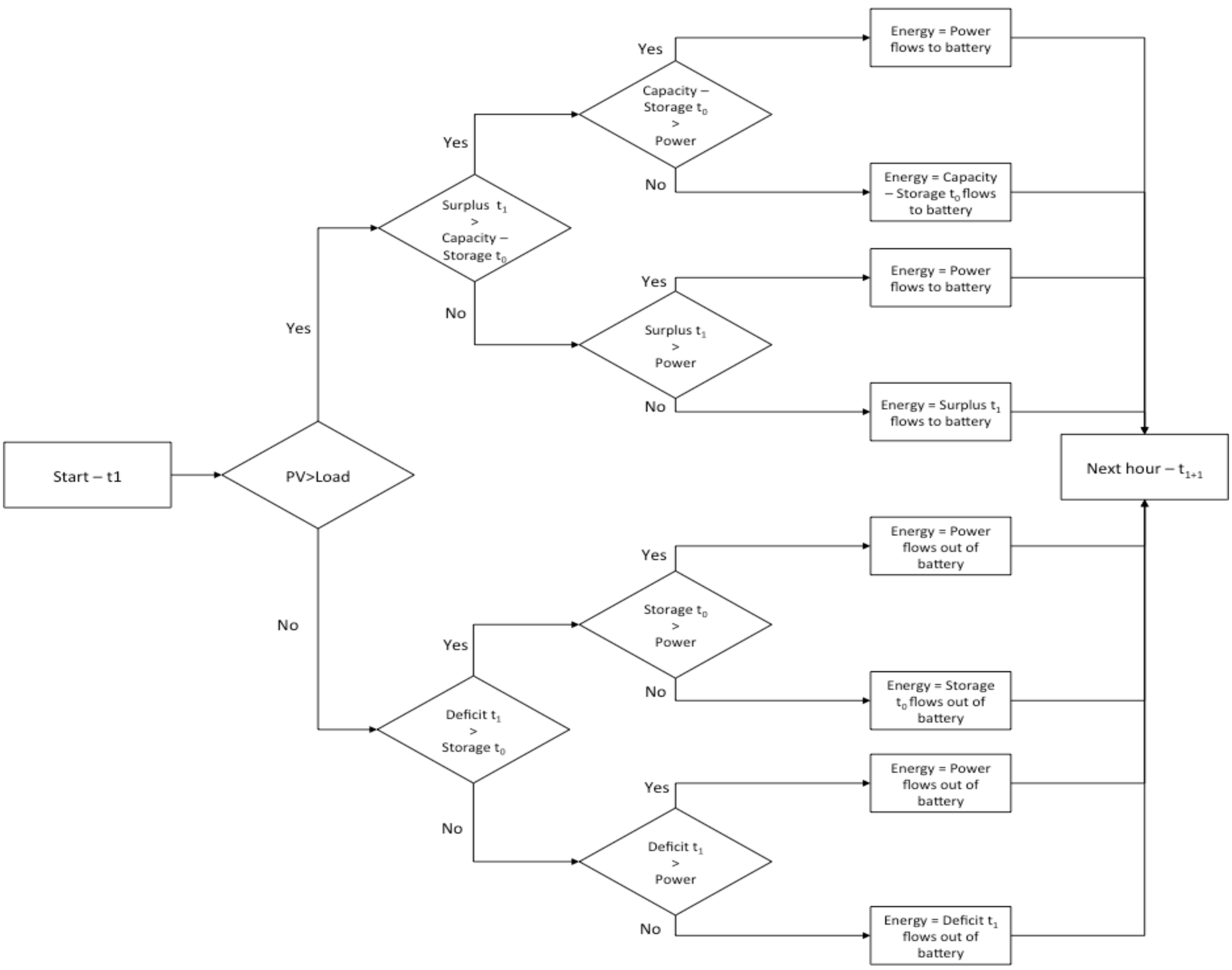
Appendix 2.2.A – Stage I underlying electrical system



Appendix 2.2.B – Stage II Underlying electrical system



Appendix 2.3.1.A – Stage I algorithm



Appendix 2.3.1.B – Exhaustive variable listing and brief explanation

In the model, there are two types of variables: endogenous and exogenous. The following formula illustrates all relevant variables present in our model:

$$\boldsymbol{NPV} = \boldsymbol{f}(storage\ capacity\ (Wh);\ PV\ Production\ capacity\ (Wn); Storage\ Power\ (W); \overline{PV\ Capex\ €\ per\ Wn}; \overline{Storage\ Capex\ \ €\ per\ Wh};\ \overline{WACC}\ (\%);\ \overline{PV\ degradation\ rate}\ (\%); \overline{Grid\ Electricity\ Prices\ (sv; vn; c; p)}\ \overline{\frac{€}{Wh}}; \overline{Load\ (Wh)};\ \overline{PV\ production\ schedule}; \overline{Efficiency\ Factor}\ (\%))$$

Appendix 2.3.1.C – Exhaustive stage I explanation

Regarding the endogenous variables:

1) PV Production Capacity. Four PV capacity scenarios were made available: 15, 17, 20 and 25 KWn. The capacity determines the maximum energy that can be captured at any given time by the PV system. The higher the PV capacity, the lower the reliance on the grid's electricity but the higher the cost of the system, hence the trade-off. Consequently, the choice of PV Production capacity determines partially the OCF and completely the PV Capex (in combination with exogenous variable - Cost of Capital).

2) Storage Capacity. It determines the maximum amount of electricity that can, at any given moment, be stored on the battery. The higher this capacity, the higher the percentage of PV production in excess of Load that will be stored. This stored Load will allow for deployment to consumption at a future time as an alternative to the more expensive grid sourcing. Storage Capacity determines partially the OCF and determines totally the Storage Unit Capex (in combination with exogenous variables).

The model has a 20-year time-span and high granularity by generating hourly observations for those 20 years, allowing for an adequate modelling of the PV production schedule with over 175.000 observations. The detailed logic of the model's algorithm follows in a logic tree structure: (see above *appendix 2.3.1.A*)

Firstly, the stage I model does a balance check, calculating whether production exceeds Load or not. Secondly, the model does a capacity check, to analyse whether the battery has capacity either to store energy or to fulfil a deficit. Thirdly, the model runs a power check, to make sure whether the desired flow falls below maximum allowed energy transmission.

An explanation in greater detail follows: for every hour, the PV production is subtracted to the Load and a deficit (Load>PV production) or a superavit (PV production>Load) is obtained. If a deficit occurs, all PV production is immediately transferred to the consumption unit and the model will check the battery for stored energy. If there is none, the deficit will have to be covered with grid sourcing. Else, if there is some, the model will calculate whether it is enough to cover the deficit. If it is not, it will transfer all stored energy and cover the difference with grid sourced energy. If it is enough, it will transfer enough energy to cover for the deficit. All these flows are subject to the power check – whether the system can support the desired flow of energy being transmitted in that span of time. For all cases where the required power exceeds the rated power, the flow will be capped at maximum power.

When a superavit occurs, the PV energy produced which fulfils the Load will be immediately consumed. The model will attempt to store the surplus in the battery, running the capacity check. If there is enough storage capacity left to accommodate the entire surplus it will be moved to the battery. Else, if there is not enough capacity, the model will store the maximum amount possible, which consists in the amount of storage left, and feed the remaining surplus to the grid at no compensation. Again all of these electricity flows are subject to the power check and capped to the maximum allowed energy transmission rate per hour.

The model calculates the savings (OCF) by analysing how much energy which originated in PV is used per hour (volume – kWh) multiplied by the price of electricity (€/KWh) at the hour of usage (and not production). There are two sources of savings: 1) Flows from PV to the consumption unit; 2) Flows from the battery to the consumption unit.

As such a numerical solution resorting to automatic iteration provided by the software package was used. The software maximised NPV, through the manipulation of the endogenous variable – storage capacity, subject to the restriction that it had to be greater than 0. All other relevant technical restrictions are built-in to the model and aren't explicitly accounted by the optimisation software. The optimal set of Storage Capacity in Wh is then obtained for each of the four PV scenarios.

Appendix 2.3.1.D – Price Tariffs

Termo tarifário fixo	EUR/mês	EUR/dia*
	25,32	0,8326

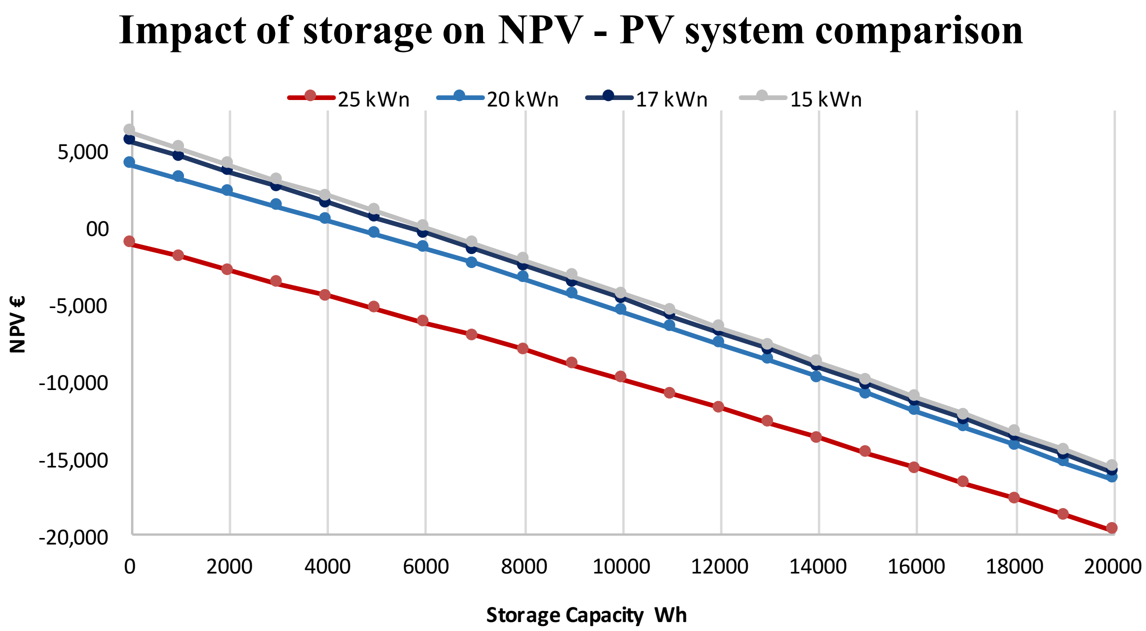
Encargos de potência	Termo	EUR/kW.mês	EUR/kW.dia*
Médias utilizações	Horas de ponta	14,407	0,4737
	Contratada	0,628	0,0206
Longas utilizações	Horas de ponta	20,467	0,6729
	Contratada	1,449	0,0476

Preço da energia ativa	Período horário		EUR/kWh
Médias utilizações	Horas de ponta	p	0,2097
	Horas de cheias	c	0,1211
	Horas de vazio normal	vn	0,0849
	Horas de super vazio	sv	0,0747
Longas utilizações	Horas de ponta	p	0,1491
	Horas de cheias	c	0,1164
	Horas de vazio normal	vn	0,0776
	Horas de super vazio	sv	0,0685

Preço da energia reativa	EUR/kVArh
Fornecida pela Rede (indutiva)	0,0293
Recebida pela Rede (capacitiva)	0,0223

The tariff is calculated through the combination of a fixed and a variable component. In terms of prices, peak/ponta (p) is the most expensive, followed by “cheias” (c), “vazio normal” (vn) and “super vazio” (sv).

Appendix 2.3.2.A – Analysis on the impact of storage on NPV – Stage I



Appendix 2.3.2.B – Data for the “Analysis on the impact of storage on NPV”

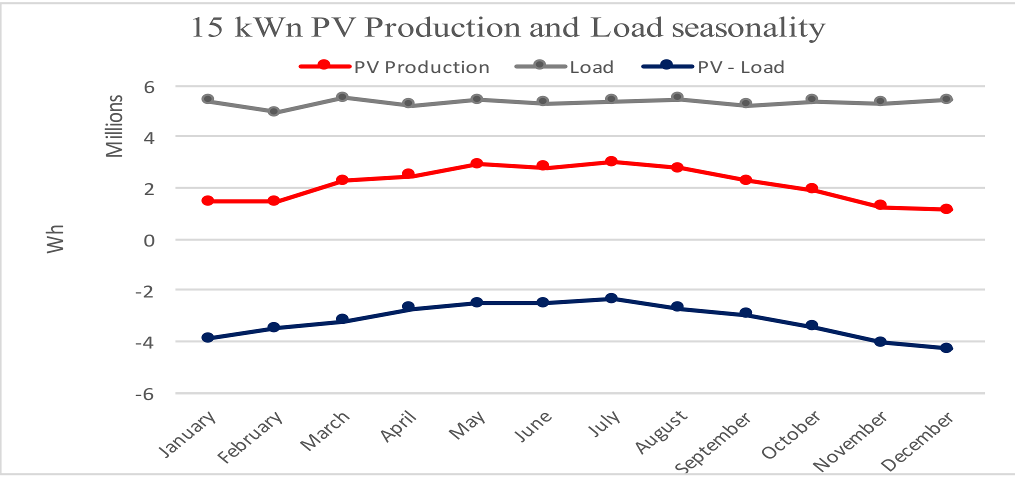
NPV Plot 25kWn auxiliary		20 kWn NPV Plot auxiliary		NPV 17 kWn Plot auxiliary		NPV 15 kWn Plot auxiliary	
Capacity Level	NPV	Capacity Level	NPV	Capacity Level	NPV	Capacity Level	NPV
0	-1066,7	0	4050,2	0	5585,5	0	6140,8
1000	-1932,9	1000	3140,2	1000	4588,1	1000	5089,1
2000	-2799,0	2000	2229,4	2000	3580,8	2000	4046,6
3000	-3648,3	3000	1327,9	3000	2578,4	3000	3020,7
4000	-4493,5	4000	424,0	4000	1580,5	4000	2006,0
5000	-5346,0	5000	-494,6	5000	577,8	5000	988,8
6000	-6207,6	6000	-1429,0	6000	-432,6	6000	-37,8
7000	-7092,8	7000	-2387,6	7000	-1456,7	7000	-1075,7
8000	-8008,2	8000	-3387,3	8000	-2513,6	8000	-2144,1
9000	-8939,4	9000	-4417,0	9000	-3592,0	9000	-3235,5
10000	-9876,3	10000	-5463,8	10000	-4679,6	10000	-4334,8
11000	-10820,7	11000	-6524,2	11000	-5773,0	11000	-5438,1
12000	-11775,4	12000	-7598,0	12000	-6875,0	12000	-6546,3
13000	-12739,2	13000	-8681,6	13000	-7986,9	13000	-7662,8
14000	-13711,1	14000	-9771,2	14000	-9107,3	14000	-8786,0
15000	-14688,1	15000	-10863,6	15000	-10232,4	15000	-9914,2
16000	-15675,8	16000	-11962,9	16000	-11362,9	16000	-11047,2
17000	-16672,1	17000	-13066,7	17000	-12497,0	17000	-12185,2
18000	-17674,8	18000	-14173,4	18000	-13632,4	18000	-13324,8
19000	-18680,6	19000	-15284,2	19000	-14769,2	19000	-14465,9
20000	-19689,2	20000	-16400,6	20000	-15906,9	20000	-15608,3

Appendix 2.3.2.C – Comparison of ΔStorage Capacity (Wh) impact on NPV (25kWn and 15kWn)

2 System Comparison		
PV capacity	25 kWn	15 kWn
Null Storage - NPV	-1067	6141
5 kWn Storage - NPV	-5345,9966	988,8123
Relative Variation	-401%	-84%
Absolute Variation	-4279,3349	-5151,9399

Analysis illustrates how the 15kWn PV system has a superior NPV. It can sustain a 5kWh system without incurring a loss. However, it registers a higher absolute loss in NPV when the storage system is introduced because it generates less energy to be stored and then profitably redeployed vs the 25kWn system.

Appendix 2.3.2.D – Analysis of seasonality in PV Production and Load 15 kWn PV



Two interest conclusions can be drawn. Firstly, there is always an aggregate monthly deficit which suggests that the PV system won't generate significant surplus to be stored, which suggests non-viability of the storage system. Secondly, while load is fairly constant, PV production exhibits significant seasonality

Appendix 2.3.2.E – Breakeven cost points for Storage System

Breakeven Price per kWh (€/kWh)	PV System			
Storage	15 kWn	17 kWn	20 kWn	25 kWn
5kWh	1397,8	1315,6	1101,1	130,8
10kWh	766,5	732,0	653,6	212,4
15kWh	539,1	517,8	475,7	220,8

In this analysis it can be seen that the higher the PV System capacity or the storage capacity, the lower must the storage system costs be to ensure breakeven

Appendix 2.3.2.F – 15 kWn PV system PV cost per kWn, WACC, Peak electricity prices

NPV		Peak Prices				
		-20%	10%	0%	10%	20%
WACC	-12,5%	€ 6 940,6	€ 7 644,8	€ 8 349,1	€ 9 053,3	€ 9 757,5
	-6,25%	€ 5 852,0	€ 6 535,5	€ 7 218,9	€ 7 902,3	€ 8 585,8
	0%	€ 4 813,6	€ 5 477,2	€ 6 140,8	€ 6 804,3	€ 7 467,9
	6,25%	€ 3 822,3	€ 4 467,0	€ 5 111,6	€ 5 756,3	€ 6 401,0
	12,5%	€ 2 875,7	€ 3 502,2	€ 4 128,8	€ 4 755,4	€ 5 382,0

NPV		PV Capex				
		-10%	-5%	0%	5%	10%
Peak Price Electricity -	-20%	€ 6 486,4	€ 4 986,4	€ 3 486,4	€ 1 986,4	€ 486,4
	-10%	€ 7 813,6	€ 6 313,6	€ 4 813,6	€ 3 313,6	€ 1 813,6
	0%	€ 9 140,8	€ 7 640,8	€ 6 140,8	€ 4 640,8	€ 3 140,8
	10%	€ 10 467,9	€ 8 967,9	€ 7 467,9	€ 5 967,9	€ 4 467,9
	20%	€ 11 795,1	€ 10 295,1	€ 8 795,1	€ 7 295,1	€ 5 795,1

NPV		PV Capex				
		-10%	-5%	0%	5%	10%
WACC	-12,5%	€ 11 934,6	€ 10 434,6	€ 8 934,6	€ 7 434,6	€ 5 934,6
	-6,25%	€ 10 496,5	€ 8 996,5	€ 7 496,5	€ 5 996,5	€ 4 496,5
	0%	€ 9 140,8	€ 7 640,8	€ 6 140,8	€ 4 640,8	€ 3 140,8
	6,25%	€ 7 861,7	€ 6 361,7	€ 4 861,7	€ 3 361,7	€ 1 861,7
	12,5%	€ 6 654,0	€ 5 154,0	€ 3 654,0	€ 2 154,0	€ 654,0

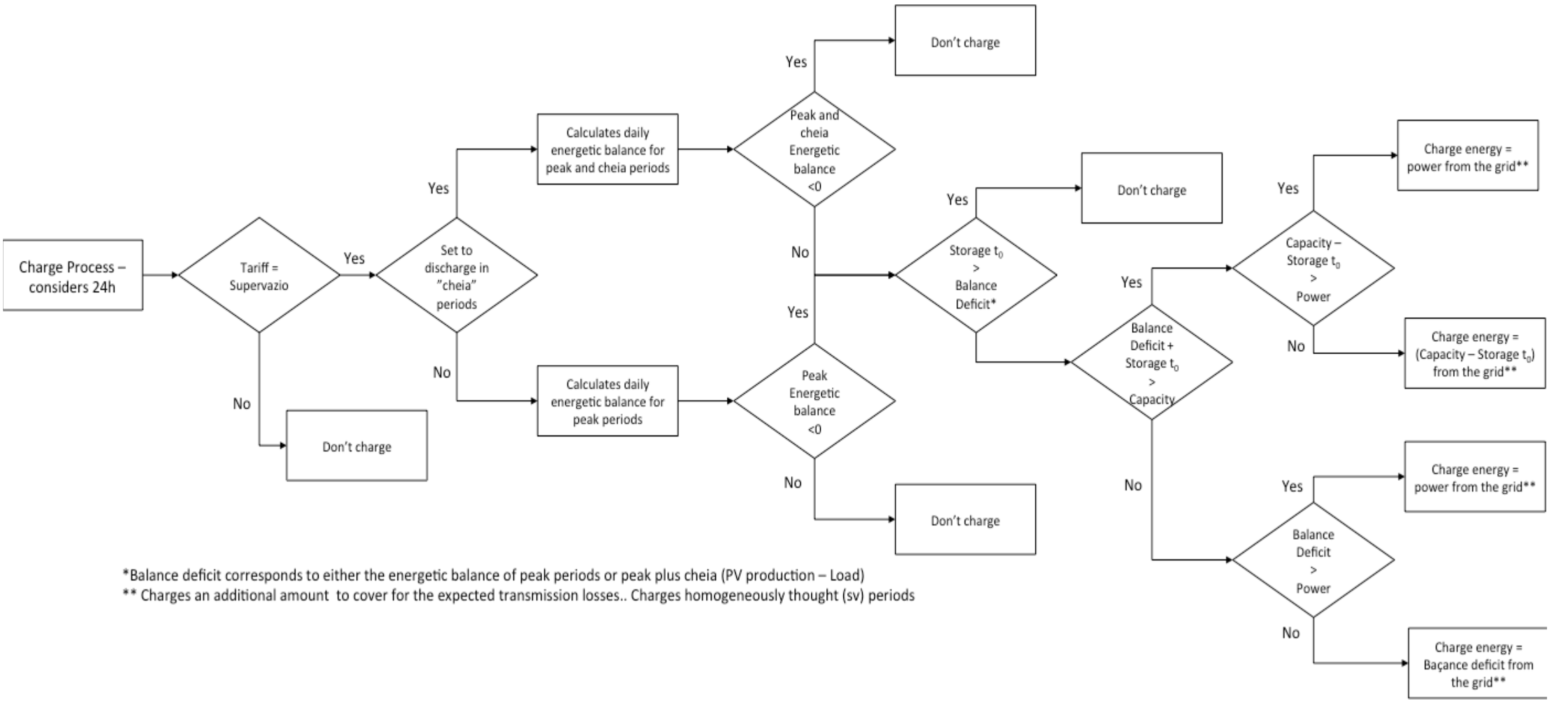
Appendix 2.3.2.G – 25 kWn PV system PV cost per kWn, WACC, Peak electricity prices

NPV		Peak Price Electricity - P				
		-20%	-10%	0%	10%	20%
WACC	-12,5%	-€ 715,7	€ 1 020,9	€ 2 757,6	€ 4 494,2	€ 6 230,9
	-6,25%	-€ 2 554,3	-€ 882,8	€ 788,7	€ 2 460,2	€ 4 131,7
	0%	-€ 4 286,9	-€ 2 676,8	-€ 1 066,7	€ 543,5	€ 2 153,6
	6,25%	-€ 5 921,0	-€ 4 368,7	-€ 2 816,5	-€ 1 264,2	€ 288,0
	12,5%	-€ 7 463,4	-€ 5 965,8	-€ 4 468,2	-€ 2 970,5	-€ 1 472,9

NPV		PV Capex - Cost per kWn				
		-10%	-5%	0%	5%	10%
Peak Price Electricity - P	-20%	€ 713,1	-€ 1 786,9	-€ 4 286,9	-€ 6 786,9	-€ 9 286,9
	-10%	€ 2 323,2	-€ 176,8	-€ 2 676,8	-€ 5 176,8	-€ 7 676,8
	0%	€ 3 933,3	€ 1 433,3	-€ 1 066,7	-€ 3 566,7	-€ 6 066,7
	10%	€ 5 543,5	€ 3 043,5	€ 543,5	-€ 1 956,5	-€ 4 456,5
	20%	€ 7 153,6	€ 4 653,6	€ 2 153,6	-€ 346,4	-€ 2 846,4

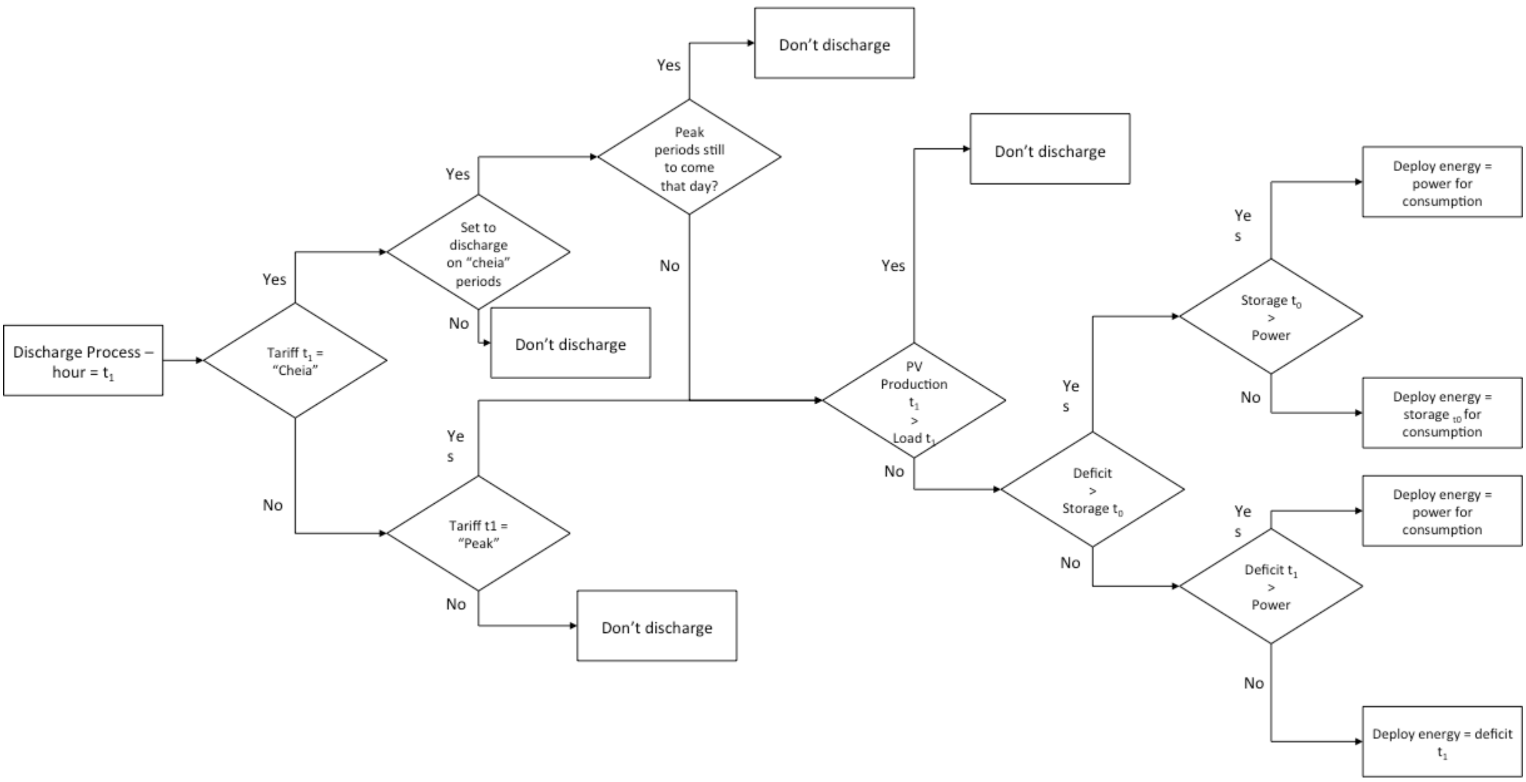
NPV		PV Capex - Cost per kWn				
		-10%	-5%	0%	5%	10%
WACC	-12,5%	€ 7 757,6	€ 5 257,6	€ 2 757,6	€ 257,6	-€ 2 242,4
	-6,25%	€ 5 788,7	€ 3 288,7	€ 788,7	-€ 1 711,3	-€ 4 211,3
	0%	€ 3 933,3	€ 1 433,3	-€ 1 066,7	-€ 3 566,7	-€ 6 066,7
	6,25%	€ 2 183,5	-€ 316,5	-€ 2 816,5	-€ 5 316,5	-€ 7 816,5
	12,5%	€ 531,8	-€ 1 968,2	-€ 4 468,2	-€ 6 968,2	-€ 9 468,2

Appendix 2.4.A – Stage II battery charging algorithm



*Balance deficit corresponds to either the energetic balance of peak periods or peak plus cheia (PV production – Load)
** Charges an additional amount to cover for the expected transmission losses.. Charges homogeneously thought (sv) periods

Appendix 2.4.B – Stage II battery discharging algorithm



Appendix 2.4.C – Exhaustive stage II explanation

The underlying logic to allowing the battery to charge from the grid is the possibility to exploit the difference in electricity price tariffs during the day. During the night, around 2 a.m., electricity prices are approximately 64% lower than peak prices. The battery would be able to source energy at those low prices and deploy the energy at the peak prices. A financial gain in the amount of the spread between the low and the peak prices could be obtained.

The battery charging process is based on a forward-looking model. In order to decide whether it is financially worthwhile to charge from the grid and how much to charge, the model must consider how much energy the battery could deploy for consumption at a profit during peak times. That requires an estimate at time t_0, of the deficit's value at time t_{0+i}. Given that weather forecasting is beyond the scope of this work, a model which combines historical data and a stochastic element was used to forecast energy usage (Load) and PV production. The baseline forecast is given by the historical data points on PV production and Load for that hour in that particular day and month in past years. The stochastic element of PV and Load is assumed to follow a Gaussian random walk. The random error's statistical distribution is assumed to have the following parameters (μ=0, ρ=0,1) *(see below Appendix 2.4.D-E)*.

After estimations on PV production and Load are concluded, the battery undergoes two processes, that of charging and that of discharging modelled through 2 distinct algorithms *(Appendix 2.3.4.A-B)*. Regarding the charging process, it firstly does a balance check, analysing whether for the following 24 hours there is an aggregate deficit or superavit. However, now the model splits this balance for the 4 electricity tariffs *(Appendix 2.3.1.D)*, checking the balance for peak periods (p), "cheia" periods (c), "vazio normal" periods (vn) and "super vazio" periods (sv). The model will only consider peak tariff periods balance and optionally cheia periods balance (in case that option is activated). Those are the tariffs with the higher spread between themselves and super vazio grid sourced electricity, which is the cheapest form of electricity for EDPD. The model will then attempt to charge the battery during the supervazio tariff periods by the amount of those balances. However, technical restrictions apply. As such the model will check whether the battery has sufficient storage capacity to store the entire deficit – capacity check. Secondly, the model would check if the required energy transmission rate would be below the maximum power cap – power check. The model also acknowledges that there will be a loss of energy during the transmission from grid to battery. Therefore it sources additional energy from the grid in the amount of the loss occurring during the charging process. Secondly the battery is also charged from the PV, whenever PV production is in excess of Load, following exactly the same rules as in the stage I model.

Regarding the discharging process, the model starts by assessing throughout the day if it is currently under a peak tariff period. In case it is, the model will run a balance check to determine if it is experiencing a deficit and if so, it is quantified. It will then run a capacity check, by comparing stored energy with the deficit to assess how much of the deficit can be served by the battery. The flow will then undergo a power check, as to make sure it meets the power criteria. In case of a "cheia" period the model will analyse whether during that day a peak period is still to follow. If so, the battery will not be discharged in "cheia", otherwise the model will attempt to discharge the battery. In order to do so, similarly to the previous case, the model will conduct a balance check followed by a capacity and power check.

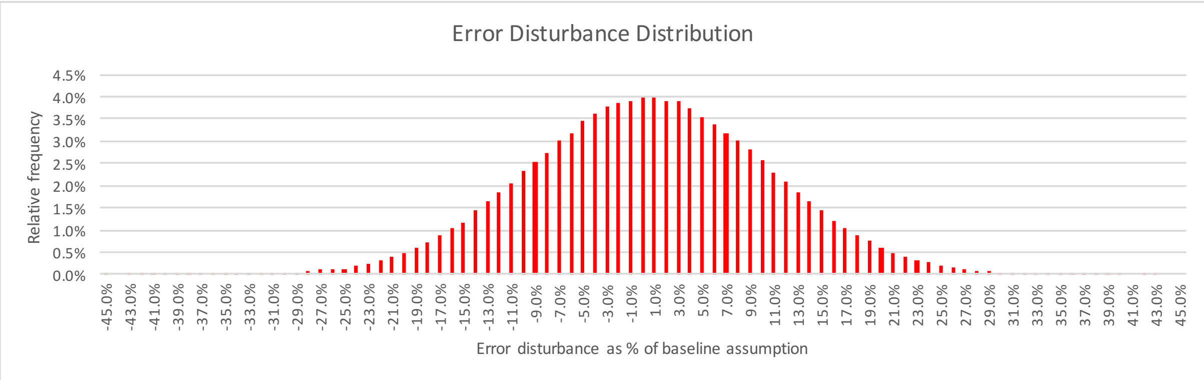
Appendix 2.4.D – Stochastic dimension of the forecast explained in further detail

The random values generated by excel are taken as the dependent variable (z = probability bounded between [0,1] of Φ(z)-1, the inverted cumulative distribution function of a standard normal distribution (μ=1, σ2=0,1). This process will be repeated for the 175200 hours. Therefore shocks will be imparted to a variable centred in 1 (100%). As an example, for a randomly generated value of 0,25, the inverted cumulative normal will return the value of

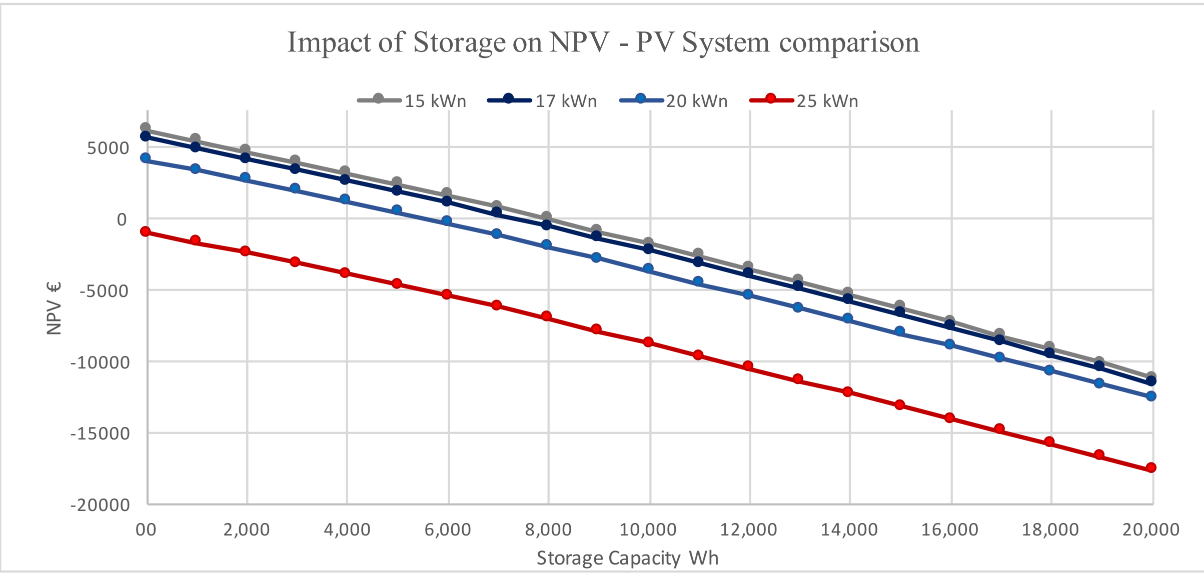
93,3%, less 6,7% than the baseline estimate. That value would then be multiplied by the baseline estimate.

The value of the random excel numbers determines the number of standard deviations which themselves determine magnitude of the stochastic shock. That number of standard deviations estimations are thus – $\varepsilon_{ti}=F-1(p_i,\mu,\sigma)$

Appendix 2.4.E– Error disturbance distribution



Appendix 2.4.1.A – Analysis of the impact of storage on NPV – Stage II



Appendix 2.4.1.B– Data for the "Analysis on the impact of storage on NPV" – Stage II

NPV 15 kWn Plot auxiliary		NPV 17 kWn Plot auxiliary		NPV 20 kWn Plot auxiliary		NPV 25 kWn Plot auxiliary	
Capacity Level	NPV	Capacity Level	NPV	Capacity Level	NPV	Capacity Level	NPV
0,0	6140,752219	0	5585,2	0	4050,2	0,0	-1067,1
1000	5391,6	1000	4869,1	1000	3372,4	1000	-1745,3
2000,0	4630,65214	2000	4120,0	2000	2649,7	2000,0	-2451,9
3000	3869,5	3000	3365,3	3000	1906,1	3000	-3179,6
4000,0	3110,288348	4000	2607,9	4000	1152,9	4000,0	-3919,9
5000	2345,0	5000	1845,6	5000	391,6	5000	-4673,6
6000,0	1565,89239	6000	1072,2	6000	-381,1	6000,0	-5441,3
7000	752,2	7000	267,4	7000	-1187,7	7000	-6244,8
8000,0	-90,5639289	8000	-573,0	8000	-2028,0	8000,0	-7083,3
9000	-942,2	9000	-1423,9	9000	-2880,0	9000	-7934,8
10000,0	-1805,63222	10000	-2290,9	10000	-3748,5	10000,0	-8807,1
11000	-2681,4	11000	-3166,6	11000	-4618,3	11000	-9683,8
12000,0	-3572,42945	12000	-4049,4	12000	-5486,5	12000,0	-10558,5
13000	-4477,9	13000	-4940,1	13000	-6354,6	13000	-11431,5
14000,0	-5396,892568	14000	-5841,9	14000	-7226,1	14000,0	-12309,2
15000	-6329,5	15000	-6757,4	15000	-8103,4	15000	-13193,3
16000,0	-7273,951407	16000	-7687,7	16000	-8986,9	16000,0	-14081,2
17000	-8230,5	17000	-8632,1	17000	-9876,7	17000	-14970,2
18000,0	-9200,291909	18000	-9594,5	18000	-10777,9	18000,0	-15861,1
19000	-10190,1	19000	-10574,5	19000	-11695,1	19000	-16754,5
20000,0	-11196,13584	20000	-11573,9	20000	-12627,1	20000,0	-17652,9

Appendix 2.4.1.C – Grid LCOE

Grid Sourcing		
Average yearly energy load kWh		63930,05
Average yearly energy cost	€	9 802,57
Average energy price - grid sourcing	€	0,153

Appendix 2.4.1.D – 15kWn PV system considered alone

PV 15 kWN alone		
Average "non-wasted" yearly energy kWh		21561,51651
Average yearly value of energy	€	3 744,54
Average energy price	€	0,142

15 kWn PV alone	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	(...)	2035
Energy Produced	21 561,5	21 561,5	21 561,5	21 561,5	21 561,5	21 561,5	21 561,5	21 561,5	21 561,5	21 561,5		21 561,5
PV of Energy Produced	19964,4	18485,5	17116,2	15848,4	14674,4	13587,4	12580,9	11649,0	10786,1	9987,2		4626,0
CAPEX	€ 30 000											
Levelised Cost of Energy	€ 0,142											

Appendix 2.4.1.E – Storage Systems 5 and 10kWh – 15 kWn PV

PV 15kWn	5 kWh Storage	10 kWh Storage
Average Yearly Energy Stored kWh	1849	3599
Average energy price @ consumption €/kWh	€ 0,2553	€ 0,2357
Average yearly value of energy	€ 472	€ 848
Average Yearly cost of grid to bat energy	€ 145	€ 248
Average yearly Price arbitrage P&L	€ 327	€ 600
Average energy price - grid sourcing	€ 0,56	€ 0,57

5 kWh Storage	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Average Cost of Energy	€ 145	€ 145	€ 145	€ 145	€ 145	€ 145	€ 145	€ 145	€ 145	€ 145
PV of CF	€ 134,07	€ 124,14	€ 114,94	€ 106,43	€ 98,54	€ 91,24	€ 84,48	€ 78,23	€ 72,43	€ 67,07
Energy Stored	1849	1849	1849	1849	1849	1849	1849	1849	1849	1849
PV of Energy Stored	1712	1585	1467	1359	1258	1165	1079	999	925	856
CAPEX	6000									
Levelised Cost of Energy	€ 0,56									

10kWh Storage	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Average Cost of Energy	€ 248	€ 248	€ 248	€ 248	€ 248	€ 248	€ 248	€ 248	€ 248	€ 248
PV of CF	€ 229,7	€ 212,7	€ 197,0	€ 182,4	€ 168,9	€ 156,4	€ 144,8	€ 134,1	€ 124,1	€ 114,9
Energy Stored	3599	3599	3599	3599	3599	3599	3599	3599	3599	3599
PV of Energy Stored	3332	3085	2857	2645	2449	2268	2100	1944	1800	1667
CAPEX	12000									
Levelised Cost of Energy	€ 0,57									

Appendix 2.4.1.F – 25kWn PV system considered alone

PV 25 kWN alone	
Average "non-wasted" yearly energy kWh	44 444,6
Average yearly value of energy	€ 5 028,13
Average energy price - grid sourcing	€ 1,01

25 kWn PV alone	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	(...)	2035
Energy Produced	5028,1	5028,1	5028,1	5028,1	5028,1	5028,1	5028,1	5028,1	5028,1	5028,1		5028,1
PV of Energy Produced	4655,7	4310,8	3991,5	3695,8	3422,1	3168,6	2933,9	2716,5	2515,3	2329,0		1078,8
CAPEX	€ 50 000											
Levelised Cost of Energy	€ 1,01											

Appendix 2.4.1.G – Storage Systems 5 and 10kWh – 25 kWn PV

PV 25kWn	5 kWh Storage	10 kWh Storage
Average Yearly Energy Stored kWh	1961,085828	3787,73835
Average energy price @ consumption €/kWh	€ 0,2560	€ 0,2286
Average yearly value of energy	€ 502,1097	€ 865,74
Average Yearly cost of grid to bat energy	€ 144	€ 229
Average yearly Price arbitrage P&L	€ 358	€ 637
Average energy price - grid sourcing	€ 0,53	€ 0,53

5 kWh Storage	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Average Cost of Energy	€ 144	€ 144	€ 144	€ 144	€ 144	€ 144	€ 144	€ 144	€ 144	€ 144
PV of CF	€ 133,40	€ 123,52	€ 114,37	€ 105,90	€ 98,05	€ 90,79	€ 84,07	€ 77,84	€ 72,07	€ 66,73
Energy Stored	1961	1961	1961	1961	1961	1961	1961	1961	1961	1961
PV of Energy Stored	1816	1681	1557	1441	1335	1236	1144	1060	981	908
CAPEX	€ 6 000,00									
Levelised Cost of Energy	€ 0,53									

10 kWh Storage	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Average Cost of Energy	€ 229	€ 229	€ 229	€ 229	€ 229	€ 229	€ 229	€ 229	€ 229	€ 229
PV of CF	€ 212,21	€ 196,49	€ 181,93	€ 168,46	€ 155,98	€ 144,42	€ 133,73	€ 123,82	€ 114,65	€ 106,16
Energy Stored	3788	3788	3788	3788	3788	3788	3788	3788	3788	3788
PV of Energy Stored	3507	3247	3007	2784	2578	2387	2210	2046	1895	1754
CAPEX	€ 12 000,00									
Levelised Cost of Energy	€ 0,53									

Appendix 2.4.1.H – Breakeven (0 NPV) prices for storage Systems

Breakeven Price per kWh (€/kWh)	PV System			
Storage - Stage II	15 kWn	17 kWn	20 kWn	25 kWn
5kWh	€ 1 669,0	€ 1 569,1	€ 1 278,3	€ 467,3
10kWh	€ 1 019,4	€ 970,9	€ 825,2	€ 319,3
15kWh	€ 778,0	€ 749,5	€ 659,8	€ 320,4

Appendix 2.4.1.I – PV systems coupled with battery payback period

Payback period - Years	PV System			
Storage - Stage II	15 kWn	17 kWn	20 kWn	25 kWn
5kWh	7,8	8	8,4	9,1
10kWh	8,7	8,8	9,1	10,1
15kWh	9,7	9,7	9,1	10,8

Appendix 2.4.1.J – Breakeven with NPV (Coupled system's NPV > PV alone's NPV) and estimate of the number of years until that breakeven takes place.

Breakeven Price per kWh (€/kWh)	PV System			
Storage - Stage II	15 kWn	17 kWn	20 kWn	25 kWn
5kWh	€ 440,9	€ 452,1	€ 468,3	€ 680,7
10kWh	€ 405,4	€ 412,4	€ 420,2	€ 426,0
15kWh	€ 368,7	€ 377,2	€ 389,8	€ 391,6

Years until breakeven with PV	PV System			
Storage - Stage II	15 kWn	17 kWn	20 kWn	25 kWn
5kWh	9,5	9,3	8,9	5,4
10kWh	10,3	10,1	10,0	9,8
15kWh	11,2	11,0	10,7	10,6

Appendix 2.4.3.A – 15 kWn PV system sensitivity analysis

NPV		Peak Prices				
		-20%	10%	0%	10%	20%
WACC	-12,5%	€ 1 719,0	€ 7 002,8	€ 5 241,5	€ 7 002,8	€ 8 764,0
	-6,25%	€ 349,5	€ 5 452,0	€ 3 751,1	€ 5 452,0	€ 7 152,8
	0%	-€ 942,3	€ 3 988,7	€ 2 345,0	€ 3 988,7	€ 5 632,4
	6,25%	-€ 2 161,8	€ 2 606,9	€ 1 017,3	€ 2 606,9	€ 4 196,5
	12,5%	-€ 3 314,2	€ 1 300,9	-€ 237,5	€ 1 300,9	€ 2 839,3

NPV		PV Capex				
		-10%	-5%	0%	5%	10%
Wacc	-12,5%	€ 8 241,5	€ 6 741,5	€ 5 241,5	€ 3 741,5	€ 2 241,5
	-6,25%	€ 6 751,1	€ 5 251,1	€ 3 751,1	€ 2 251,1	€ 751,1
	0%	€ 5 345,0	€ 3 845,0	€ 2 345,0	€ 845,0	-€ 655,0
	6,25%	€ 4 017,3	€ 2 517,3	€ 1 017,3	-€ 482,7	-€ 1 982,7
	12,5%	€ 2 762,5	€ 1 262,5	-€ 237,5	-€ 1 737,5	-€ 3 237,5

NPV		PV Capex				
		-10%	-5%	0%	5%	10%
Peak Price Electricity -	-20%	€ 2 057,7	€ 557,7	-€ 942,3	-€ 2 442,3	-€ 3 942,3
	-10%	€ 3 701,4	€ 2 201,4	€ 701,4	-€ 798,6	-€ 2 298,6
	0%	€ 5 345,0	€ 3 845,0	€ 2 345,0	€ 845,0	-€ 655,0
	10%	€ 6 988,7	€ 5 488,7	€ 3 988,7	€ 2 488,7	€ 988,7
	20%	€ 8 632,4	€ 7 132,4	€ 5 632,4	€ 4 132,4	€ 2 632,4

NPV		PV Capex				
		-10%	-5%	0%	5%	10%
Storage Unit Capex	-50%	€ 8 345,0	€ 6 845,0	€ 5 345,0	€ 3 845,0	€ 2 345,0
	-25%	€ 6 845,0	€ 5 345,0	€ 3 845,0	€ 2 345,0	€ 845,0
	0%	€ 5 345,0	€ 3 845,0	€ 2 345,0	€ 845,0	-€ 655,0
	25%	€ 3 845,0	€ 2 345,0	€ 845,0	-€ 655,0	-€ 2 155,0
	50%	€ 2 345,0	€ 845,0	-€ 655,0	-€ 2 155,0	-€ 3 655,0

NPV		Storage Unit Capex				
		-50%	25%	0%	25%	50%
Storage Unit Capacity	-50%	€ 5 750,3	€ 3 500,3	€ 4 250,3	€ 3 500,3	€ 2 750,3
	-25%	€ 5 549,5	€ 2 174,5	€ 3 299,5	€ 2 174,5	€ 1 049,5
	0%	€ 5 345,0	€ 845,0	€ 2 345,0	€ 845,0	-€ 655,0
	25%	€ 5 116,4	-€ 508,6	€ 1 366,4	-€ 508,6	-€ 2 383,6
	50%	€ 4 831,4	-€ 1 918,6	€ 331,4	-€ 1 918,6	-€ 4 168,6

Appendix 2.4.3.B – 25 kWn PV system sensitivity analysis

NPV		Peak Prices				
		-20%	10%	0%	10%	20%
WAC(	-12,5%	-€ 4 912,8	€ 1 349,7	-€ 737,8	€ 1 349,7	€ 3 437,2
	-6,25%	-€ 6 792,2	-€ 749,1	-€ 2 763,4	-€ 749,1	€ 1 265,3
	0%	-€ 8 564,2	-€ 2 728,3	-€ 4 673,6	-€ 2 728,3	-€ 783,0
	6,25%	-€ 10 236,3	-€ 4 596,3	-€ 6 476,3	-€ 4 596,3	-€ 2 716,3
	12,5%	-€ 11 815,5	-€ 6 360,9	-€ 8 179,1	-€ 6 360,9	-€ 4 542,7

NPV		PV Capex				
		-10%	-5%	0%	5%	10%
Wacc	-12,5%	€ 4 262,2	€ 1 762,2	-€ 737,8	-€ 3 237,8	-€ 5 737,8
	-6,25%	€ 2 236,6	-€ 263,4	-€ 2 763,4	-€ 5 263,4	-€ 7 763,4
	0%	€ 326,4	-€ 2 173,6	-€ 4 673,6	-€ 7 173,6	-€ 9 673,6
	6,25%	-€ 1 476,3	-€ 3 976,3	-€ 6 476,3	-€ 8 976,3	-€ 11 476,3
	12,5%	-€ 3 179,1	-€ 5 679,1	-€ 8 179,1	-€ 10 679,1	-€ 13 179,1

NPV		PV Capex				
		-10%	-5%	0%	5%	10%
Peak Price Electricity - I	-20%	-€ 3 564,2	-€ 6 064,2	-€ 8 564,2	-€ 11 064,2	-€ 13 564,2
	-10%	-€ 1 618,9	-€ 4 118,9	-€ 6 618,9	-€ 9 118,9	-€ 11 618,9
	0%	€ 326,4	-€ 2 173,6	-€ 4 673,6	-€ 7 173,6	-€ 9 673,6
	10%	€ 2 271,7	-€ 228,3	-€ 2 728,3	-€ 5 228,3	-€ 7 728,3
	20%	€ 4 217,0	€ 1 717,0	-€ 783,0	-€ 3 283,0	-€ 5 783,0

NPV		PV Capex				
		-10%	-5%	0%	5%	10%
Storage Unit Capex	-50%	€ 3 326,4	€ 826,4	-€ 1 673,6	-€ 4 173,6	-€ 6 673,6
	-25%	€ 1 826,4	-€ 673,6	-€ 3 173,6	-€ 5 673,6	-€ 8 173,6
	0%	€ 326,4	-€ 2 173,6	-€ 4 673,6	-€ 7 173,6	-€ 9 673,6
	25%	-€ 1 173,6	-€ 3 673,6	-€ 6 173,6	-€ 8 673,6	-€ 11 173,6
	50%	-€ 2 673,6	-€ 5 173,6	-€ 7 673,6	-€ 10 173,6	-€ 12 673,6

NPV		Storage Unit Capex				
		-50%	25%	0%	25%	50%
Storage Unit Capacity	-50%	-€ 1 312,7	-€ 3 562,7	-€ 2 812,7	-€ 3 562,7	-€ 4 312,7
	-25%	-€ 1 484,6	-€ 4 859,6	-€ 3 734,6	-€ 4 859,6	-€ 5 984,6
	0%	-€ 1 673,6	-€ 6 173,6	-€ 4 673,6	-€ 6 173,6	-€ 7 673,6
	25%	-€ 1 887,8	-€ 7 512,8	-€ 5 637,8	-€ 7 512,8	-€ 9 387,8
	50%	-€ 2 163,7	-€ 8 913,7	-€ 6 663,7	-€ 8 913,7	-€ 11 163,7

Appendix for Limitations

Appendix 2.6.A PV System Prices

	Prices for PV Systems	Capacity Range	Year	Area
NREL, 2013	2,14 €	10-100 kWn	2013	Germany
IEA, 2013	2,000-2,800 €	5-20 kWn	2012	Italy
Roland Berger, 2015	2,000 USD	5-20 kWn	2015	Europe

Appendix 2.6.B– Detailed information on the limitations regarding the PV System

In Europe 2015, prices for residential PV systems (5-20kWn) are around USD 2000/kW (Confais, E., Fages, E., & Van Den Berg, W., 2015). Consequently, the incorporated price assumption of €2000/kW in the model is well-founded. EDPD uses monocrystalline Silicon (mono-Si) based PV module in Évora. According to Jordan & Kurtz 192 mono-Si modules in Arcata, CA, USA, over 11 years of exposure display on average a low 0.4%/year degradation rate (Jordan & Kurtz, 2012). Arcata and Évora are subject to similar climatic conditions as they are on the same latitude. Thus the use of 0.7% PV degradation rate is justified.

Appendix 2.6.C – Expected development of key characteristics of Li-ion batteries

	Prices		Efficiency		Calendar Life		Cycle Life	
	2014	2020	2014	2030	2014	2030	2014	2030
ENEA, 2014	300 - 1,200 €							
IRENA, 2015	1,000 - 2,000€	200-900 €						
Lazard, 2015	1,2	600						
Fuchs, 2012	1,10 €	750	0,85	0,9	5 - 20 years	10 - 30 years	1,000 - 3,000	5,000 - 10,000

Sources: ENEA, 2014; IRENA, 2015; Lazard, 2015; Fuchs, 2012

Appendix 2.6.D – Li-ion subcategory characteristics

	Cathode	Anode	Electrolyte	Energy density	Cycle life	2014 price per kWh	Prominent manufacturers
Lithium iron phosphate	LFP	Graphite	Lithium carbonate	85-105 Wh/kg	200-2000	USD550-USD850	A123 Systems, BYD, Amperex, Lishen
Lithium manganese spinel	LMO	Graphite	Lithium carbonate	140-180 Wh/kg	800-2000	USD450-USD700	LG Chem, AESC, Samsung SDI
Lithium titanate	LMO	LTO	Lithium carbonate	80-95 Wh/kg	2000-25000	USD900-USD2,200	ATL, Toshiba, Le-clanché, Microvast
Lithium cobalt oxide	LCO	Graphite	Lithium polymer	140-200 Wh/kg	300-800	USD250-USD500	Samsung SDI, BYD, LG Chem, Panasonic, ATL, Lishen
Lithium nickel cobalt aluminum	NCA	Graphite	Lithium carbonate	120-160 Wh/kg	800-5000	USD240-USD380	Panasonic, Samsung SDI
Lithium nickel manganese cobalt	NMC	Graph-ite, silicon	Lithium carbonate	120-140 Wh/kg	800-2000	USD550-USD750	Johnson Controls, Saft

Source: IRENA, 2015 based on Jaffe, S. & Adamson, K.A., 2014

Appendix 2.6.E – Detailed limitation of the battery storage market

Most of the input data was given by EDP directly and therefore needs some critical assessed to what extent they represent values that can be found in the market. Therefore, the most important metrics of a Li-ion storage battery were reviewed and future developments and the influence on the NPV assessed. As performance and prices of Li-ion batteries are highly dependent on the chemicals used, market research was studied in order to assess the relevant metrics (see Appendix 4.5).

EDP provided a price for the whole battery system of € 1,200/kWh. Although there are cheaper availabilities in the market, in order to reach a certain level of efficiency and durability, the price is reasonable, although a rather moderate assumption. Furthermore, moderate predictions regarding the price expect a decrease over the next years to only around €600/kWh in 2020 (Lazard, 2015; IRENA, 2015). Other research gives an estimated linear decrease of 10% per year (KPMG, 2016). This would have a positive effect on this project and the diffusion of the technology overall. All in all it has to be said that there is a wide range of prices in the market regarding different chemical specifications of batteries and therefore make an exact assumption difficult (see Appendix 4.6).

Furthermore, EDP provided a lifetime of the battery of ten years which corresponds to around 3,600 cycles overall. It is a reasonable, though rather conservative assumption. Contemporary research characterises normal ageing of Li-ion batteries as a lifetime of 15 years and strong ageing as a lifetime of 12.5 years (Naumann et al., 2015). Furthermore, battery R&D is expected to slightly improve the life expectancy of batteries. Therefore, a longer than expected lifetime of the battery would have a positive impact on the NPV. Li-ion batteries are expected to improve in terms of durability and can be expected to hold 20 years in the near future and up to 30 years and 10,000 cycles in 2030 (Fuchs, 2012)..

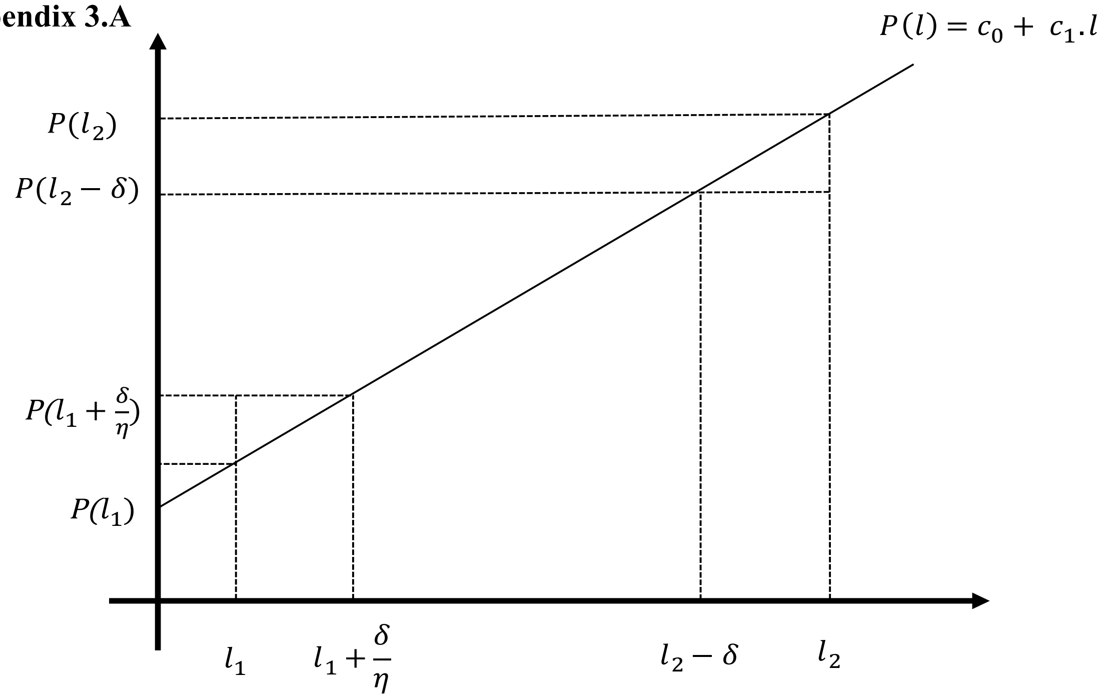
An efficiency factor of 85% is in line with market research data and therefore represents a good approximation. The efficiency factor is not expected to change much during the next years and only slightly improve to around 90% until 2030 (Fuchs, 2012).

Overall it can be said that EDPD's assumptions regarding the battery storage system were consistent with market data. The conservative estimates would even give room for an improved NPV.

Appendix 2.6.F –WACC reality check

Another input factor that was provided by EDP is the WACC. As there is no information given about the capital structure of the project, CAPM is a good way to calculate the WACC. Based on a 10yrs treasury yield of 2% as a risk-free rate, a beta of EDP of 0.8 (Yahoo Finance, 2016) and an assumed market return of 7% the CAPM would give a discount rate of only 6%. At first this seems to be much lower than the 8% that is given by EDP. The implicit incorporation of a fudge factor of 2p.p. to account for country risk is not unreasonable.

Appendix 3.A



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